Problem Domain Reference Model - GMLC 1.2.1

Functional Groups and Reference Architectures for the Electric Grid

October 2020

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Revision History

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PNNL	11/29/2019	Completion	Final
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Summary

This “Problem Domain Reference Model” (PDR) is an “as-built” high-level description of the electric power system as of early 2018. It primarily reflects the North American system though many of the characteristics are also typical of electric power systems worldwide.

The problem domain reference model provides context and a baseline for forward looking grid architecture development. More specifically, this document provides the context for the U.S. Department of Energy Grid Modernization Laboratory Consortium (GMLC) Grid Architecture core team’s development of reference architectures for: Advanced Bulk Energy Systems, High Resilience Grids, High Distributed Energy Resources (DER) Penetration and High Automation Grids, Microgrids and Segmented Distribution Grids, and Urban Converged Networks. The document is included in the package of documents associated with each of the reference architectures.

Acronyms and Abbreviations

ADMS	Advanced Distribution Management System
AESO	Alberta Electric System Operator
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
BA	Balancing Authority
BAA	Balancing Authority Area
CAISO	California Independent System Operator
CCA	Community Choice Aggregation
CFTC	Commodity Futures Trading Commission
Co-op	Cooperative
CR	Competitive Retailer
C&I	Commercial and Industrial
DA	Distribution Automation
DAM	Day Ahead Market
DER	Distributed Energy Resources
DFR	Digital Fault Recorder
DG	Distributed Generator
DERMS	Distributed Energy Resource Management System
DMS	Distribution Management System
DOE	Department of Energy
DP	Distribution Provider
DR	Demand Response
DS	Distributed Storage
DSO	Distribution System Operator
ED	Economic Dispatch
EIA	Energy Information Administration
EIM	Energy Imbalance Market
EMS	Energy Management System
EPA	Environmental Protection Agency
ER	Entity-Relationship
ERO	Electric Reliability Organization
ERCOT	Electric Reliability Council of Texas

FAN	Field Area Network
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location, Isolation and System Restoration
FRCC	Florida Reliability Coordinating Council
GIS	Geographic Information System
GMLC	Grid Modernization Laboratory Consortium
GO	Generation Owner
GOP	Generator Operator
HVDC	High Voltage Direct Current AMI
IC	Interchange Coordinator
ICE	Intercontinental Exchange
ICT	Information and Communication Technology
IESO	Independent Electric System Operator
IMM	Independent Market Monitor
IOU	Investor Owned Utilities
IPP	Independent Power Producer
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
LMP	Locational Marginal Price
LSE	Load Serving Entity
MDMS	Meter Data Management System
MISO	Midwest Independent System Operator
MOU or Muni	Municipally Owned Utility
MRO	Midwest Reliability Organization
NERC	North American Electric Reliability Corporation
NOIE	Non Opt In Entity
NPCC	Northeast Power Coordinating Council
NRC	Nuclear Regulatory Commission
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
OASIS	Open Access Same Time Information Service
OATT	Open Access Transmission Tariff
OMS	Outage Management System
OPF	Optimal Power Flow

OTC	Over-the-Counter
PC	Planning Coordinator
PDR	Problem Domain Reference
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PLC	Programmable Logic Controllers
PMA	Power Marketing Administration
PMU	Phasor Measurement Unit
PSC	Public Service Commission
PSE	Purchasing-Selling Entity
PUC	Public Utility Commission
PUCT	Public Utility Commission of Texas
PUD	Public Utility District
RC	Reliability Coordinator
REP	Retail Electric Provider
RF	ReliabilityFirst
RP	Resource Planner
RRE	Regional Reliability Entity
RTM	Real Time Market
RTO	Regional Transmission Operator
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SERC	SERC Reliability Corporation
SPP	Southwest Power Pool
STATCOM	Static Synchronous Compensator
SVC	Static VAr Compensator
TO	Transmission Owner
TOP	Transmission Operator
TP	Transmission Planner
TRE	Texas Reliability Entity
TSP	Transmission Service Provider
TVA	Tennessee Valley Authority
UC	Unit Commitment
VER	Variable Energy Resources

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1.0 Introduction

The North American electric grid is one of the largest integrated systems in the world. The energy infrastructure is one of the enabling critical infrastructure sectors on which most of the other critical infrastructure sectors (e.g. emergency services, water, healthcare, communications, information technology, manufacturing, transportation etc.) are dependent for their functioning[1]. It is vast in geographical expanse and connects utility-scale electric power plants and Distributed Energy Resources (DER) to deliver electricity through a complex system of power lines and substations. According to the U.S. Energy Information Administration (EIA), there were about 8652 power plants which had operational generators with combined nameplate capacity of at least 1 megawatt (MW) in the U.S. at the end of 2017[2]. The interconnected networks consist of hundreds of thousands of miles of transmission lines and millions of miles of distribution lines which ultimately deliver electricity to nearly 145 million customers throughout the U.S.[3]

Affordable, reliable and resilient operation of the electricity infrastructure requires integration and coordinated operation of the numerous subsystems which may be owned, managed and regulated by different entities. Identifying these entities and understanding their functions as well as their inter-relationships is key to obtaining a complete picture of how these entities cooperate and coordinate their activities to provide seamless services.

1.1 Problem Domain Reference Model (PDR)

This "Problem Domain Reference Model" (PDR) is an "as-built" high-level description of the electric power system as of early 2018. It primarily reflects the North American system though many of the characteristics are also typical of electric power systems worldwide. The problem domain reference model provides context and a baseline for forward-looking grid architecture development.

The U.S. Department of Energy (DOE) Grid Modernization Laboratory Consortium (GMLC) Grid Architecture team has developed industry structures for various regions of the U.S. Each region's industry structure is represented in Entity-Relationship (ER) diagram which shows the entity classes that function in a coordinated manner to ensure stable and reliable operation of the regional electric grid, the relationships existing between the entity classes, and the functional groups formed by them. Industry structure diagrams have been developed for California (CA ISO service area), New York, Texas (ERCOT service area), and Pacific Northwest (BPA service area). Market control diagrams have also been developed which show the processes that are implemented by CAISO and NYISO to operate the wholesale electric market. The conceptual model described in this report serves as a framework for the development of as-built grid architecture diagrams which can serve as the baseline in grid-related planning, development and operation. These one-diagram visualizations of the entire system can assist in determining gaps in technology, organization and/or regulation.

The PDR is divided into three major sections - General Structure, Basic Entity Classes, and Functional Groups. The General Structure described in Section 2.0 provides a high-level, integrated view of an electric power system from end-to-end. Section 3.0 describes how ER diagrams have been adapted for the development of Industry Structure diagrams of the regional grids. Some of the common entity classes which form the building blocks of such industry structure diagrams have been briefly described. Section

[1] DHS, "Energy Sector", Available at: https://www.dhs.gov/cisa/energy-sector, Accessed: 01/14/2019.
[2] EIA, "How many power plants are there in the United States?", Available at: https://www.eia.gov/tools/faqs/faq.php?id=65&t=2, Accessed: 01/14/2019.
[3] EIA, "U.S. electric system is made up of interconnections and balancing authorities", Available at: https://www.eia.gov/todayinenergy/detail.php?id=27152, Accessed: 01/14/2019.

4.0 takes a closer look at seven specific functional groups present in the electric power system. Other sections include a glossary / list of acronyms and a summary of the objectives for each reference architecture case. References indicated within the text and included in the footnotes provide more detailed background information or point to existing grid architecture work.

The GMLC Grid Architecture core team is developing reference architectures for: Advanced Bulk Energy Systems, High Resilience Grids, High Distributed Energy Resources (DER) Penetration and High Automation Grids, Microgrids and Segmented Distribution Grids, and Urban Converged Networks. This PDR provides the context for the development of these reference architectures.

2.0 General Structure

This section of the PDR summarizes the basic structure of the electric power system and the interactions between the elements of the system.

2.1 High Level Structure of the Electric Power System

The electric power system can be decomposed by considering the major functional elements. At the highest level this decomposition is bulk power and distribution. Considering electricity as a commodity this can be thought of as production and distribution of the commodity. As is described in the subsequent discussion of the system, this simple view is historical and is changing.

Bulk power consists of generating units for large-scale power production, and the transmission infrastructure to move the power to distribution systems. With the deregulation of the electric power system in the late 1990's the two elements were separated. In many parts of the United States competitive markets were established for bulk generation. Organizations were established to operate the competitive markets and to operate the majority of the transmission infrastructure.

Figure 1 shows the overall decomposition as seen in the traditional grid. A description of each element of the figure is provided.

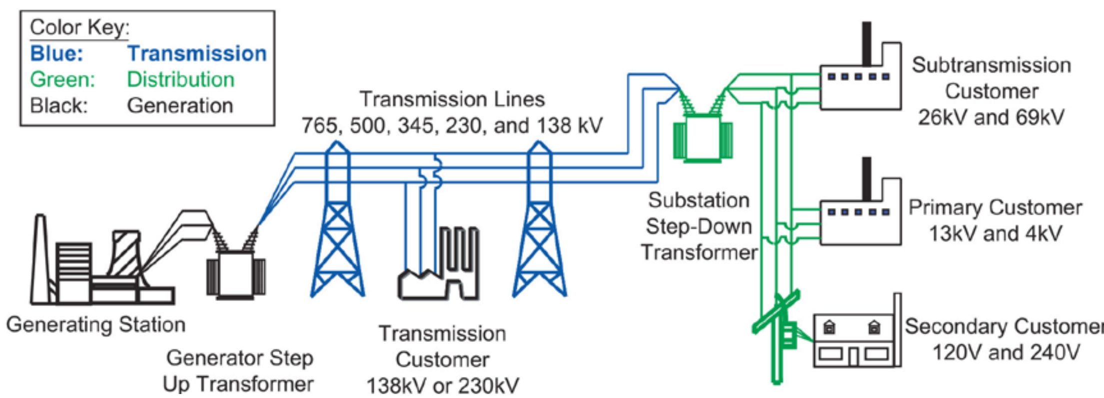

Figure 1: Simplified view of traditional power system

Source: Federal Energy Regulatory Commission

A useful basic reference on this material providing additional details (as of about 2014) is the "United States Electric Industry Primer" published by the U. S. DOE Office of Electricity Delivery and Energy Reliability[1].

2.1.1 Bulk Generation

Bulk generation consists of various types of generation including thermal generation, hydropower generation, and non-hydro renewable generation (primarily wind and solar). Thermal generation may be further decomposed according to the source of thermal energy. These sources include: burning of fossil fuels such as coal and natural gas, burning of other fuels such as garbage (methane is produced from decomposition of garbage or other biomasses), or any other thermal source that involves material

[1] U.S. DOE Office of Electricity Delivery and Energy Reliability, "United States Electric Industry Primer", DOE/OE-0017, July 2015, Available at: energy.gov/sites/prod/files/2015/12/f28/united-states-electricity-industry-primer.pdf, Accessed: 01/14/2019.

combustion. Additional forms of thermal generation include nuclear and geothermal. Thermal generation units come in various sizes and have different operating characteristics and dynamics leading to different roles in the system. Hydropower is generated by turbines driven by movement of water. At large scales, hydropower is realized through construction of dams, and generation levels are varied by managing the flow of water through the turbines. At a smaller scale, turbines are placed in run-of-river or other natural, continuous water flows. Hydropower is a form of renewable generation since the “fuel”, water, is replenished through natural weather cycles. It is often, however, considered separately from other renewable generation for historical and policy reasons. Thermal and hydropower generation both involve large turbines that provide inertial mass important for frequency regulation.

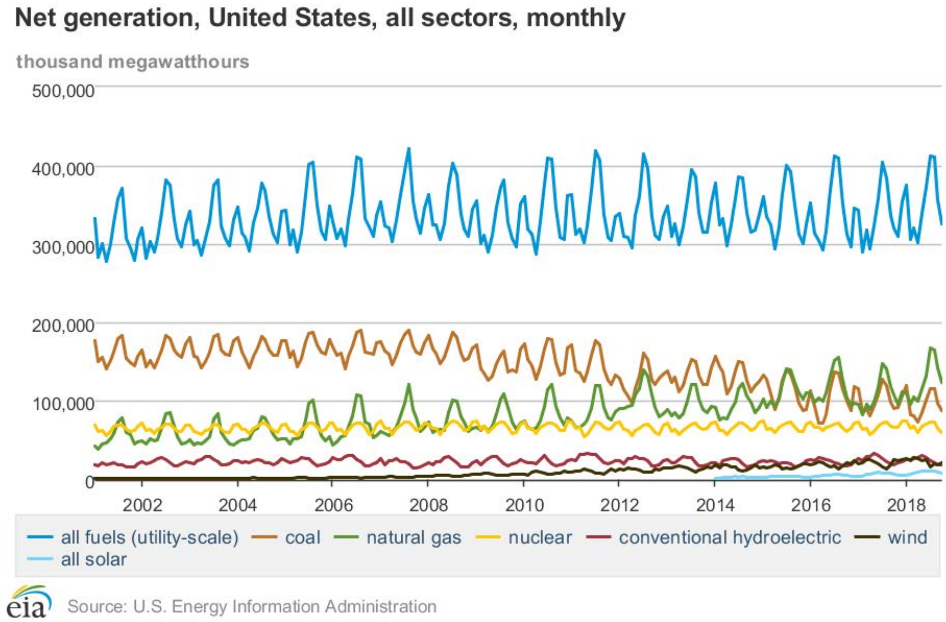

Figure 2: Monthly net electricity generation from different fuels[1]

Non-hydro renewable generation from large scale wind and solar have different operating characteristics due to their lack of inertial mass and their intermittency. Bulk scale wind and hydro generation share a characteristic in that the generation location may be at a large distance from population centers where the electricity is needed.

Figure 2 shows the time series of monthly net generation of electricity in the U.S. from the different types of resources that have been discussed above, i.e. coal, natural gas, nuclear, conventional hydroelectric, wind and solar.

2.1.2 Transmission

In the bulk power system, the generated electricity is transmitted usually over long distances using transmission system infrastructure. In the United States the transmission system is primarily a high voltage AC system though there is growing consideration of and use of high voltage DC (HVDC). Voltage levels in the U.S. bulk power system range from 115 kV to over 765 kV with the higher voltages generally corresponding to transmission corridors that cover longer distances. The structure of the transmission network is generally a mesh providing multiple pathways for electricity delivery and providing higher system reliability.

[1] EIA, “Electricity Data Browser”, Available at: https://www.eia.gov/electricity/data/browser/, Accessed: 01/11/2019.

The transmission system in the United States is broken into four major areas: The Eastern Interconnection, the Western Interconnection, the Québec Interconnection, and the Electric Reliability Council of Texas (ERCOT) Interconnection. Each interconnection is responsible for synchronous operation independent of the others, and there are limited numbers DC interties. A map illustrating the geographic delineation of the interconnections is included and discussed in more detail later in the PDR.

2.1.2.1 Transmission System Structure and Operations

In the transmission system, apart from the power transmission lines, which are primarily responsible for moving power across geographical distances, another critical component is the transmission substation. Transmission substations serve two roles. First, they connect the segments of the transmission system forming the mesh referenced earlier. Some substations, known as switching stations, only serve this role. Second, they serve as the interconnection points into and out of the transmission system. Transmission substations are also used to change voltage levels. Generator step-up transformer between the generating power station and the transmission line steps up the voltage to a higher level in order to minimize the energy lost in transmission lines. Within the transmission network they may also step voltage up or down as needed. At the points of interconnection of the transmission system to distribution systems the transformers in transmission substations step the power down to the sub-transmission (typically 69 kV) or medium voltages (4 kV to 43 kV) needed in primary distribution systems.

Transmission system operations are discussed in greater details in Sections 3.2.14 and 4.8 of the PDR.

2.1.3 Distribution

Electricity distribution systems receive power at combined transmission and distribution system substations where voltage is stepped down and the responsibility for provisioning of electric power to customers taken on by the distribution system providers. There are some exceptions to this for a special class of “direct service” customers who have a need for significant quantities of electric power and may connect to a transmission system substation directly rather than going through a distribution utility. An example of this is aluminum smelters.

2.1.3.1 Distribution System Structure

As mentioned, at the transmission substation the voltage of the AC power is stepped down, using transformers, to a medium voltage for transfer from the transmission system to sub-transmission system which may be providing electricity to sub-transmission customers. Transformers are also used in the distribution substations where the power is further stepped down for distribution through “feeders”. Distribution substations may also have a variety of sensors for monitoring the status of the distribution system, in particular voltage sensors. Distribution system substations have circuit breakers that protect the system from short circuits in the substation or on one or more feeders. These circuit breakers can be a limiting factor on the hosting of local generation (usually photovoltaic (PV)) on a distribution feeder. Reverse power flows can appear to the circuit breaker to be a fault causing it to trip. Distribution substations may also have capacitor banks, or the transformers may include tap-changers for managing reactive power and voltage respectively.

Feeders

Distribution feeders bring the power from the distribution substation to service transformers where the voltage level is stepped down for delivery to customers. In the U.S. there are typically a small number of customer premises connected to a transformer. There are five to nine customers typically served by a pole mounted transformer, and three to five for a pad mounted transformer. (Note that this is different from other parts of the world where there may be as many as a couple of hundred customers on the low-voltage side of the very much larger transformer. Such non-U.S. systems have a different secondary structure, voltage levels and transformer sizes.)

Primary feeders in the U.S. are typically three-phase, wye-connected, with a multi-grounded neutral wire. They may run for long distances and can have thousands of connected customers. Feeders may have main branches (each branch is three-phase) and will have branching laterals that may consist of one, two, or all three phases, but are typically single phase. Laterals typically have fuses located at the branching-off points from the main feeder.

There are a number of feeder topologies in use in the U.S. but two basic topologies for distribution feeders are common: radial (possibly with partial meshing via feeder back ties) and fully meshed secondaries. Figure 3 illustrates these two topologies.

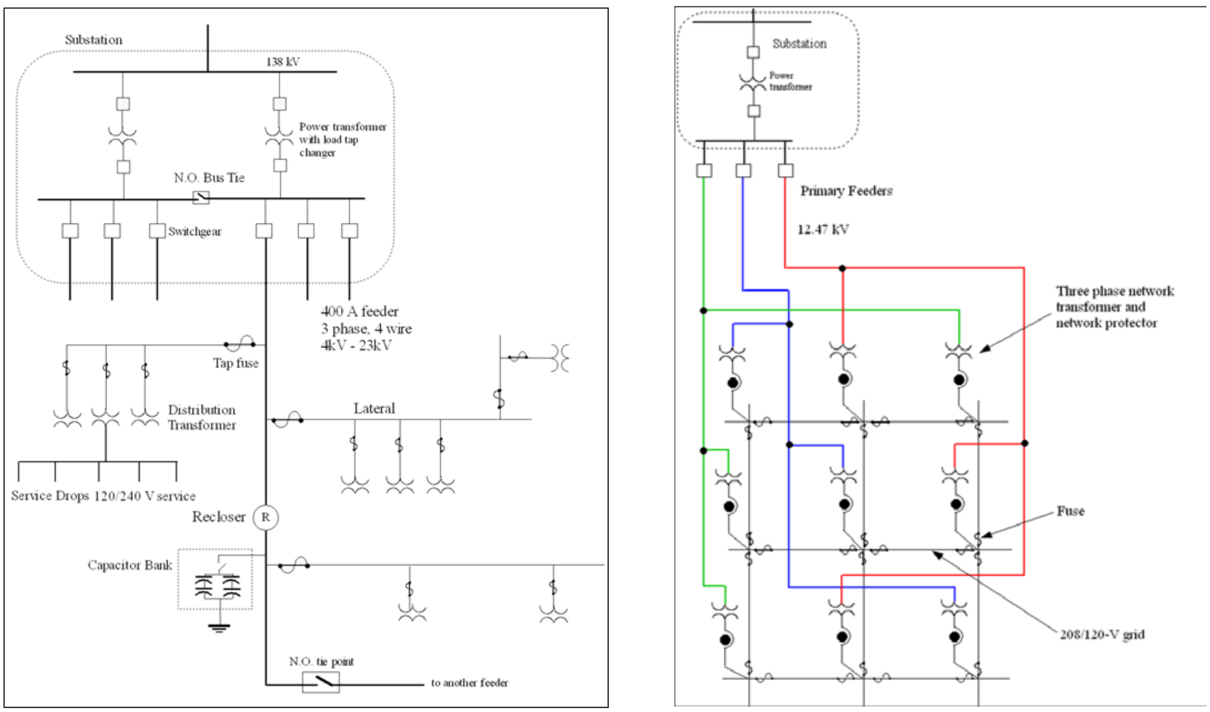

Figure 3: Partially meshed primary distribution feeders (left) and dense secondary mesh distribution system (right)

Radial Feeders

Almost all distribution systems include some number of radial feeders to allow reconfigurations. They are referred to as "radial" because of the "hub and spoke" structure with multiple feeders coming from a distribution substation to the customers. A substation may have from four to 30 feeder circuits. Most feeders have load connections all along their lengths, but some feeders ("express feeders") have no load connections until they reach a distant area such as a business district or residential development.

Feeders typically have pieces of equipment attached at various points. These include switches and reclosers, line drop (voltage) compensators, and shunt capacitor banks. Instrumentation of various kinds may exist, such as faulted circuit indicators, voltage and or current line sensors, sensing capabilities built into other line equipment such as reclosers, sag and sway sensors, icing sensors, and so on. However, for many distribution systems there is actually very little instrumentation and for the smaller utilities, there may not even be any distribution SCADA system to collect such data. This is one of the reasons why schemes involving distribution state estimation and locational marginal pricing are not feasible. There is research work related to use of synchronized phasor measurement (microPMUs) for distribution, but only limited pilot deployments exist. Consequently, some data is collected over time from automated meter systems but otherwise, the utility is restricted to line sensing and so can determine voltage, current, real and reactive power flow, waveform distortion, etc. but not synchronized phase relationships such as PMU networks provide on transmission systems.

Service Drops

Connections from the primary feed to loads is typically through a service or distribution transformer. The service transform steps down voltage from the primary feeder level to 240 volts with a split phase. On the primary side the service transformer may be connected from one phase to ground or may be connected to two of the phases. On the secondary side the phase is split so that there are three wires: a neutral, a 120-volt line and another 120-volt line that is 180 electrical degrees out of phase with the first so that connecting across the two hot lines yields 240 volts. A three-wire service drop from the secondary bus to the premises (via the revenue meter) provides the connection to the breaker box on the premises. Such a transformer provides single phase electric service to a load. While three phase service transformers exist, it is more common for technical and utility inventory management reasons to use a cluster of three single phase pole-mount transformers to supply three phase power to a customer such as a restaurant or small office building. On the secondary (load) side of the service transformer, the three-wire connection constitutes a bus, referred to as a feeder secondary. This secondary bus may span several utility poles and multiple customer sites may be connected to a single secondary, and so these sites are connected to each other by that secondary bus (however in sparsely populated rural areas, there may be only one customer per transformer). This is an important consideration when rooftop solar or storage inverters are being connected to the grid, since these connections are generally made at the feeder secondary level. Improper operation of such inverters can cause voltage regulation problems, affecting other customers on that same secondary bus.

Underground residential distribution transformers are generally larger than pole-mount service transformers are concrete pad-mounted and connect to load one of two ways: via individual cables from the transformer directly to the residences or via a loop circuit (usually operated open on one end) that has taps to the residences. In either case, the loads are connected to each other via the loop or the bus bar located in the pad mount transformer. Generally, pad mount transformers serve a small number of large homes.

Meshed Feeders

Some distribution systems are more heavily interconnected resulting in a meshed or partially meshed network for distribution feeders. The dense secondary mesh arrangement is more typical in central urban areas and is located underground. Manhattan’s electric distribution system, for example, is heavily meshed. Meshed distribution systems provide more flexibility in routing power to customers and generally provide higher reliability than simple radials, due to the existence of alternate power routing paths through the network. They employ specialized equipment (notably network transformers and network protectors) not seen on above-ground systems. Service connections are typically made via an underground entrance to the building basement switchgear.

2.1.3.2 Distribution System Operations

Distribution system operations involve those management and control activities undertaken by the distribution utility to assure safe and reliable delivery of electricity to end users. Depending on the size and sophistication of the utility these may be highly automated using intelligent devices or largely manual. Operation of distribution system is a real-time activity that uses data originating in substations, intermediate operational elements and end-use points.

Utilities have staff that monitor and control the distribution system from centralized control centers. There is typically an operator in the loop for distribution system operations. Distribution grid protection and control functions include:

- Flow control
- Volt/VAR regulation
- Voltage stabilization
- Line and equipment fault protection
- Fault isolation

For grids with increasing penetration of DER, there may able be DER coordination and storage State of Charge (SoC) control functions. In the case of microgrids, there may be islanding and re-synchronization control elements although this is usually done from within the microgrid.

A variety of IT and operational automation systems may be in use in distribution systems, including:

- Substation SCADA
- Substation gateways
- Distribution SCADA
- Remote Capacitor Control Systems (RCCS)
- Advanced Meter Infrastructure (AMI) or Automatic Meter Reading (AMR) systems
- Geographic Information Systems (GIS)
- Outage Management Systems (OMS)
- Distribution Management Systems (DMS)
- Integrated Voice Response (IVR) systems
- Distributed Energy Resources Management Systems (DERMS)
- Fault Location, Isolation, and Service Restoration (FLISR) systems

However, it should be noted that there is no particular uniformity across the industry in the U.S. Some of the smaller distribution system operators do not even have distribution SCADA.

Distribution utilities tend to have multiple communications systems (it is not unusual to see six or more) and will often use a mix of private and telecom service provider networks. Most operational networks are wired or wireless hub-and-spoke connections from the field to the control center. In many of the larger utilities, substation communications are via optical fiber, often in the form of Sonet. For a few of the more advanced utilities, field communications have evolved into a two-tier arrangement, with the upper tier being a multi-services network and the lower tier consisting of a number of purpose-built field area and neighborhood area networks (often wireless or wireless mesh).[1] Despite the hype, 5G communications plays no role in distribution utility operations as of 2020 and will not before 2025 at the earliest. Many utilities have already determined that they will skip 5G entirely.[2]

2.1.4 Customers, DER Owners, and DER Operators

The purpose of the electric power system has historically been to deliver the commodity of electricity to customers. By the later 20th Century, this had begun to change organically and over time penetration of distribution-connected resources has proliferated to the point where in some distribution utilities DER

[1] JD Taft, Advanced Networking Paradigms for High-DER Distribution Grids, PNNL-25475, May 2016, available online: https://gridarchitecture.pnnl.gov/media/advanced/Advanced%20Networking%20Paradigms%20final.pdf

[2] JD Taft, The Impact of 5G Telecommunications Technology on US Grid Modernization 2017–2025, PNNL-27068, April 2019, available online: https://gridarchitecture.pnnl.gov/media/advanced/Communications_final_v2_GMLC.pdf

represents both a challenge and an opportunity. New roles and some new entities have developed in response and the industry has gone through a period of experimentation with new business models. For a while the term "prosumer" was common, but this has been replaced by a better understanding of the relationships involved. The roles of consumer, DER owner and DER operator may be fulfilled by the same or separate entities. Consequently, it is more useful to consider the roles and their mappings to entities rather than monolithic labels such as prosumer. Figure 4 illustrates the concept in Entity-Relationship (E-R) diagram form. Note that while DER Operator roles have been filled by third part aggregators for a while, the business model for this has proven to be marginal, so that increasingly DER aggregators have been exiting the business or becoming DER aggregation platform operators or suppliers and the function do DER aggregation is shifting away from private sector third parties.

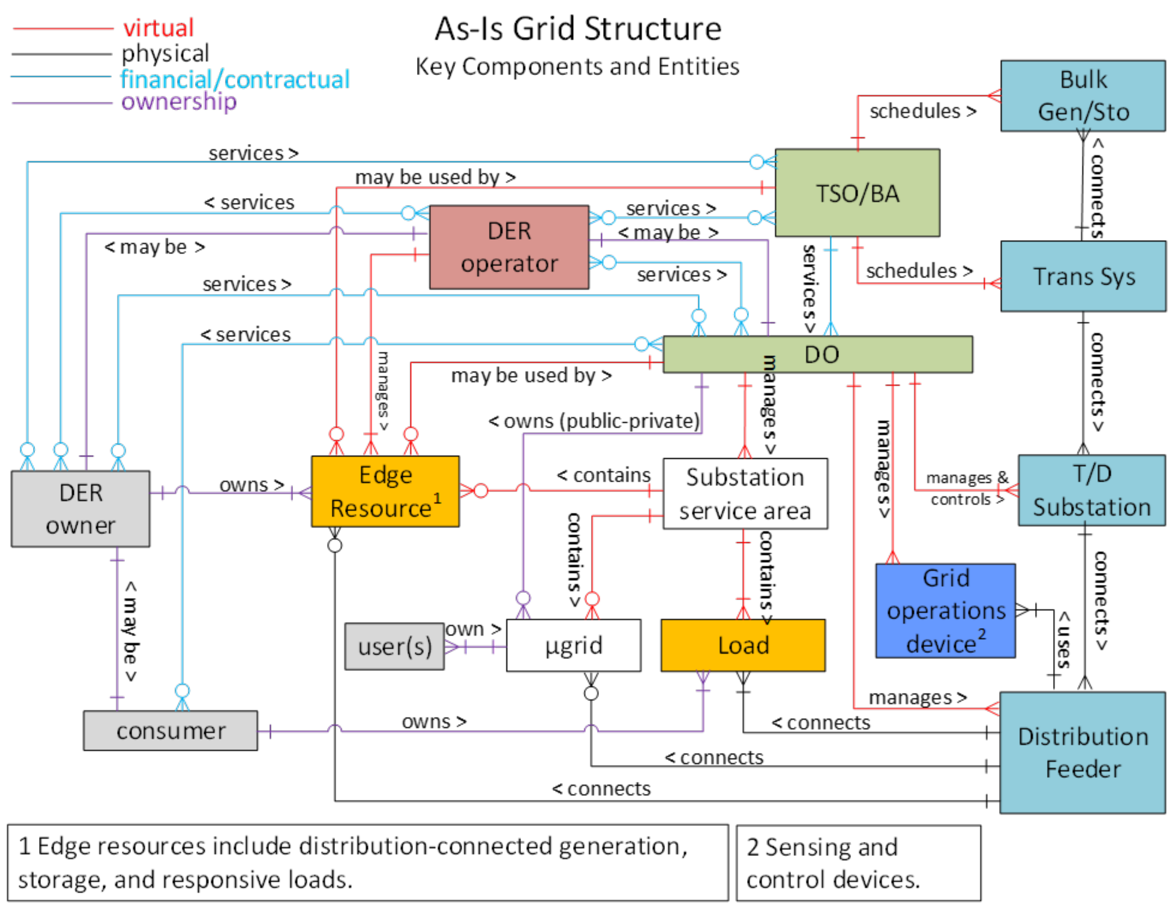

Figure 4: Modern Grid Systems, Roles, and Entities E-R Diagram

For all classes of customers some level of metering is required to measure consumption and bill the customers. In the U.S. deployment of Advanced Metering Infrastructure (AMI), sometimes referred to as smart meters, is continuing. There is not universal deployment. There are also a range of suppliers and capabilities of AMI. In some cases, early adopters still are limited to automated meter reading (AMR) and do not have the broader range of capabilities typical of AMI. There is a new generation of AMI just starting to be deployed with sensing, computing and communication capabilities included in the meter enabling the possibility of edge computing. Figure 4 shows a view of the modern grid which has distributed generation, grid energy storage, and more advanced sensors like smart meters.

There are four major categories of customers differentiated by a combination of typical location, level of consumption, and nature of consumption: residential, commercial and industrial and transportation. A high-level overview of these four categories of customers will be provided in Section 3.2.24, 3.2.25 and 3.2.26.

2.1.4.1 Distributed Energy Resources

DER were initially considered to be those assets in a distribution system at a customer premises or a utility location that could generate electricity. Currently the definition has been expanded to include assets at either type of location that are capable of generation and/or flexible behavior. This expanded definition includes energy storage and responsive loads. Within storage, electric energy storage is a special case since it may be a source or a sink of electricity. Other storage types, thermal for example, will generally only be a flexible load or offset consumption since it will not provide electricity back into the electric power system.

Customer-owned DER that supply power are the basis for the term "prosumer" mentioned above. They involve the use of inverters to transform DC power into AC power for injection into the distribution system. Historically inverters were limited in their capabilities. Currently, there are a growing number of jurisdictions requiring the use of smart inverters conforming to the IEEE 1547 revision or ISO/IEC smart inverter standards. These inverters are capable of being configured and controlled. They can provide measurements and are also capable of providing reactive power and real power voltage support.

Electric utilities have tariffs and interconnection agreements that govern how consumer or third party DER may be connected to the distribution grid. Such connections may be limited by three types of grid constraints:

- Voltage
- Thermal
- Protection

Electric utilities that have experienced significant levels or DER connection requests typically publish hosting capacity maps to show where there are concentrations of DER and where this is capacity to accept additional DER.

The control and coordination of DER is the subject of much ongoing work, not just in terms of technology, but also in terms of regulations, tariffs and rules, and even large-scale industry structure. The ongoing discussion about Distribution System Operators (DSOs) in the US is about the coordination between Transmission Operators and Distribution Operators to manage DER for the benefit of both Transmission and Distribution.[1]

The question of how to coordinate DER and how to employ distribution level DER markets is part of the continuing industry effort to resolve the evolution of the grid into a bifurcated energy source structure.[2] In addition, the architectures to provide structure for both control (allocation) based and market based coordination methods are developmental, but certain underlying principles are gaining traction across the industry.[3]

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[1] P De Martini and L Kristov, Distribution Systems In A High Distributed Energy Resources Future, FUER Report No. 2, October 2015, available online: https://gridarchitecture.pnnl.gov/media/advanced/FEUR_2%20distribution%20systems%2020151022.pdf

[2] P De Martini, et al., Evolving Distribution Operational Markets, available online: https://gridarchitecture.pnnl.gov/media/advanced/Caltech_Evolving_Distribution_Markets.pdf

[3] JD Taft, Architectural Basis for Highly Distributed Transactive Power Grids: Frameworks, Networks, and Grid Codes, PNNL-25480, June 2016, available online: https://gridarchitecture.pnnl.gov/media/advanced/Architectural%20Basis%20for%20Highly%20Distributed%20Transactive%20Power%20Grids_final.pdf

3.0 Basic Entity Classes in Industry Structures

Modeling and visualization of the industry structures of the regional grids using Industry Structure diagrams is of great interest to stakeholders in the electric industry and beyond. Industry structure diagrams assist in identifying which organizations are involved in providing the mentioned functions (federal regulation, state regulation, reliability coordination, control and coordination, energy and ancillary services, market, retail) in the grid, and how they interact with each other for the seamless delivery of that function.

3.1 Entity-Relationship Diagrams

An Entity-Relationship (ER) Diagram is a data modelling tool for identifying and categorizing organizations into entity classes and defining the relationships between them. Industry structures of regional grids are depicted by grid architects using Entity-Relationship (ER) diagrams.

3.1.1 Entity Classes

Entity classes are representative of entire groups of organizations or entities and are represented by boxes with labels indicating their names. For example, the "Federal Regulators" entity class consists of all the federal-level organizations that regulate the electric grid of the region being considered. Typically, an entity class does not represent a single organization unless it has only one member.

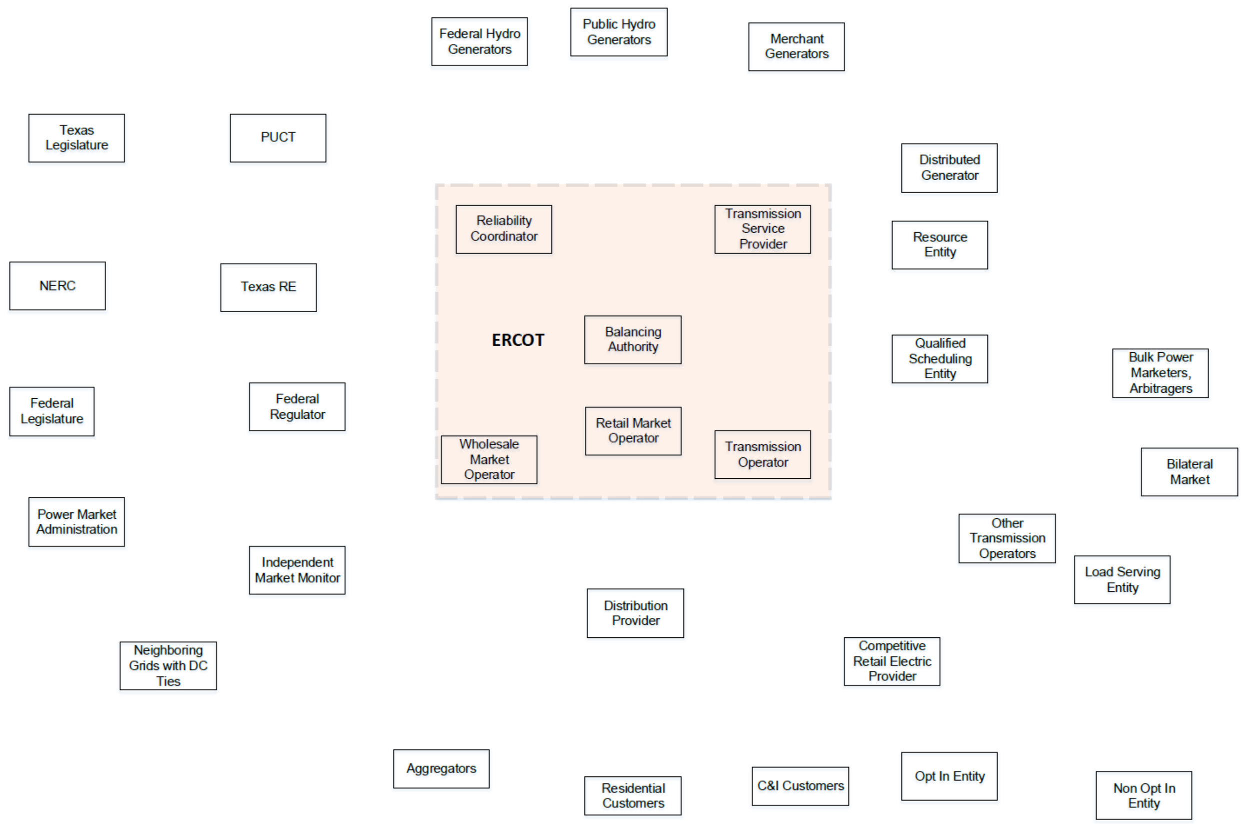

Figure 5: Entity classes in the Industry Structure diagram of ERCOT

Even when we are looking at industry structures of regional grids in U.S., they can vary widely based on the characteristics and the needs of the region. The very first step of developing an Industry Structure diagram involves identifying the organizations that are involved in delivering the different functions and categorizing them into entity classes. Figure 5 and Figure 6 show the entity classes that are present in the Industry Structure diagrams of Texas region with focus on ERCOT's service area, and Pacific Northwest region with focus on BPA's service area respectively. The position of an entity box in the diagram does not have any particular significance. Note that overview most of the entity classes shown in these figures will be provided in Section 3.0.

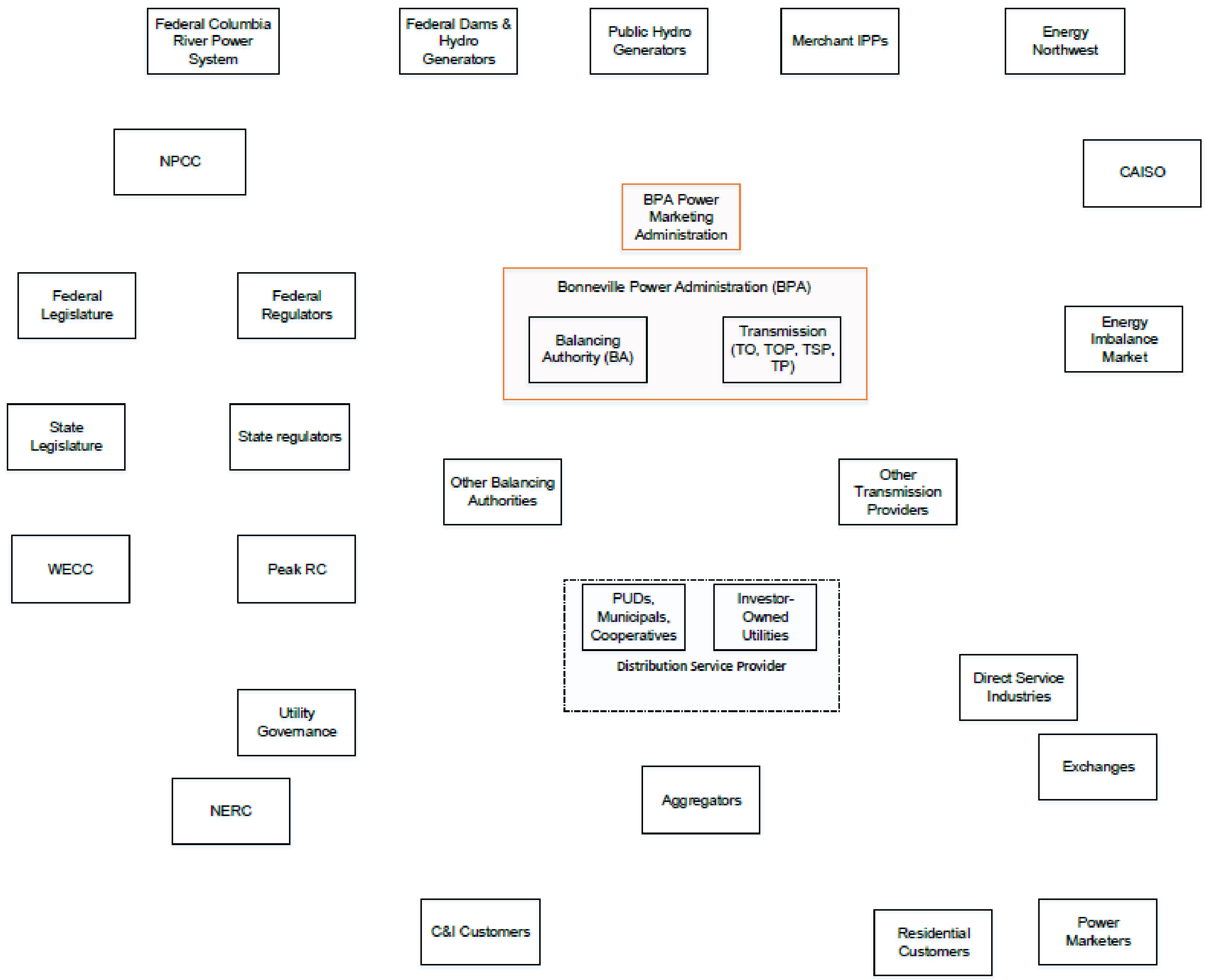

Figure 6: Entity classes in the Industry Structure diagram of the Pacific Northwest

Although the structures are largely different, there are some entity classes which are common to both of these regional grids. It should be noted that these common entity classes in different regions may consist of different number of member entities, may interact with different set of entity classes, and their styles of interaction may also vary.

At present Industry Structure diagrams are complete for the following regions:

- State of New York
- State of California (focus on CA ISO's service area)
- Texas region (focus on ERCOT's service area)
- Pacific Northwest region focusing on the area served by Bonneville Power Administration (BPA).

3.1.2 Relationships

Relationship between any pair of entity classes are groups of behaviors between them. A relationship is represented by a line connecting the pair of entity class boxes and terminate in symbols which indicate how many members of the entity class can be involved in that relationship, or in words, the cardinality of the relationship. The line is labeled with summarized description of the primary relationship, and angle brackets at the ends of this text indicate its directionality. Figure 7 shows the symbols and formats that have been used for representing the cardinality and directionality of the relationships.

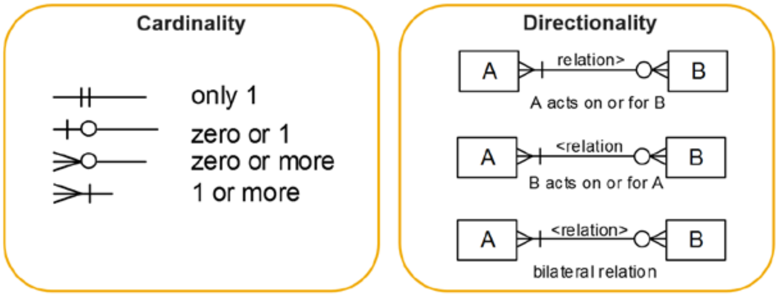

Figure 7: Cardinality and directionality symbols

3.2 Basic Entity Classes

This subsection presents the entity classes which are commonly present in industry structures of regional grids of the U.S., and briefly discusses about their member entities, and the typical responsibilities. The relationships between pairs of entity classes is important and will discussed further in the **Error! Reference source not found.** Section later in this report.

3.2.1 Federal Legislature

Federal legislatures define the scope of the various regulatory entities at the federal level. They may also define incentives for investment or other action within the industry and by consumers.

3.2.2 Federal Regulators

The Federal Regulators entity class primarily consists of the Federal Energy Regulatory Commission (FERC), Environmental Protection Agency (EPA), Nuclear Regulatory Commission (NRC), Department of Energy (DOE), and Commodity Futures Trading Commission (CFTC).

3.2.2.1 Federal Energy Regulatory Commission (FERC)

FERC is an independent agency within the U.S. Department of Energy (DOE) which has regulatory authority over interstate transmission. It regulates sales of wholesale electricity in interstate commerce, as well as provides oversight of regional wholesale markets. It also establishes financial rules for all entities of the bulk power system, such as the firewall rules between financial activities and transmission system operations. Other responsibilities include licensing and inspecting hydroelectric projects and overseeing environmental matters related to them and protecting reliability of high voltage interstate transmission by enforcing reliability standards.[1] As an independent regulatory agency, FERC's decisions are only reviewable by the Federal courts, and are not subject to review by the President of the United States or the Congress[2]. The FERC commissioners are presidential appointees.

[1] FERC, " What FERC Does", Available at: https://www.ferc.gov/about/ferc-does.asp?csrt=17756983823587868113, Accessed: 01/14/2019.

[2] U.S. DOE Office of Electricity Delivery and Energy Reliability, "United States Electric Industry Primer", DOE/OE-0017, July 2015, Available at: energy.gov/sites/prod/files/2015/12/f28/united-states-electricity-industry-primer.pdf, Accessed: 01/14/2019.

3.2.2.2 Environmental Protection Agency (EPA)

EPA establishes environmental rules that affect generation of electric power.

3.2.2.3 Nuclear Regulatory Commission (NRC)

NRC has oversight of the construction, commissioning, and operation of nuclear power plants.

3.2.2.4 Department of Energy (DOE)

DOE is responsible for implementing policies regarding the different energy resources.

3.2.2.5 Commodity Futures Trading Commission (CFTC)

CFTC has jurisdiction over the derivatives market (which is a financial market for trading futures, options etc.), but not the physical sale of electricity.

3.2.3 State Legislatures

State legislatures play one of the key roles in developing policies, providing recommendations, or in some other cases signaling support or opposition to certain policies and initiatives, and also urging federal action if needed. They can provide funding, incentives or mandates for advancing grid technologies. For example, state legislature may establish incentives or renewable portfolio standards that apply to all utilities within the state. They establish the regulatory construct for Investor Owned Utilities (IOUs), and sometimes other utilities, within their state, which is then applied by the state-level utility regulatory body.

3.2.4 State Regulators

In the U.S., regulatory commissions have been established by the 50 states and the District of Columbia for overseeing the operations and transactions of electric energy in their jurisdiction. These commissions may take different names like Public Utility Commissions (PUC), Public Service Commissions (PSC), corporation commissions, or commerce commissions[1]. Areas which are considered outside of FERC's jurisdictional responsibility, for example retail electricity sales or regulation of distribution facilities, are regulated by the state regulators.

3.2.4.1 Public Utility Commission (PUC)

PUC is the regulatory body within a state of jurisdiction that applies laws and regulations to the subject entities. Generally, PUCs have jurisdiction over distribution of energy within the state, intrastate retail sales of electricity, siting and physical construction of transmission facilities, generation facilities, and distribution systems, and adoption of performance standards for the distribution systems. Their responsibilities also include determining revenue of utilities and establishing rates for customers[2].

3.2.4.2 Other State Level Organizations

In some states there are other entities such as energy commissions or offices, environmental protection agencies, or others with some regulatory jurisdiction over utilities operating within the state.

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[1] P. Nanavati and J. Gundlach, "The Electric Grid and Its Regulators- FERC and State Public Utility Commissions", Available at: http://columbiaclimatelaw.com/files/2016/09/Nanavati-Gundlach-2016-09-Adaptation-Chapter-re-Elec-Grid.pdf, Accessed: 01/14/2019.

3.2.5 North American Electric Reliability Corporation (NERC)

NERC is a not-for-profit international regulatory authority tasked with assuring reliability and security of the bulk power system in North America. After the blackout in 1965 which left about thirty million people in northeastern U.S. and southeastern Ontario, Canada without power, NERC was established initially as a voluntary association by the utility industry following the recommendation of FERC[1]. NERC's area of responsibility covers the continental U.S., Canada as well as the northern portion of Baja California, Mexico. Currently, NERC is designated as the U.S. government's Electric Reliability Organization (ERO) subject to oversight by the FERC. Some of the responsibilities of NERC include development and enforcement of reliability standards, annual assessment of reliability, monitoring of bulk power system as well as education, training and certification of industry personnel[2].

NERC also developed a Reliability Functional Model which defines and describes a number of functions[3]. Each function is a set of tasks that must be performed in order to ensure reliability of the bulk electric system and is assigned to a functional entity which is responsible for the identified tasks. The model also explains the relationships between various functional entities.

Table 1: List of NERC Functional Entities

Functional Entity		**Function Name**	**High-level Summary of Function**[9]
Name	**Acronym**		
Reliability Coordinator	RC	Operating Reliability	Maintains real-time operating reliability of bulk electric system within its area
Balancing Authority	BA	Balancing	Integrates resource plans ahead of time, maintains generation-load-interchange-balance in real-time
Generator Owner	GO	Generator Ownership	Owns and maintains generating units
Generator Operator	GOP	Generator Operations	Operates generating units and performs functions of supplying energy and reliability related services
Transmission Owner	TO	Transmission Ownership	Owns and maintains transmission entities
Transmission Operator	TOP	Transmission Operations	Ensures real-time operating reliability of the transmission assets within its area
Transmission Service Provider	TSP	Transmission Service	Administers transmission tariff and provides transmission service under applicable transmission service agreements
Transmission Planner	TP	Transmission Planning	Develops a long-term plan for reliability of its interconnected bulk electric transmission systems
Distribution Provider	DP	Distribution	Provides facilities that interconnect and transfer electrical energy to end-use customer
Purchase-Selling Entity	PSE	Purchase-Selling	Purchases or sells, and takes title to, energy, capacity, and reliability related services
Load-Serving Entity	LSE	Load-Serving	Secures energy and transmission service to serve the end-use customers

[1] NERC, "History of NERC", Available at: https://www.nerc.com/AboutNERC/Documents/History%20AUG13.pdf, Accessed: 01/14/2019.
[2] NERC, "About NERC", Available at: https://www.nerc.com/AboutNERC/Pages/default.aspx, Accessed: 01/14/2019.
[3] NERC, "NERC Reliability Functional Model – Version 5", Available at: https://www.nerc.com/pa/Stand/Pages/FunctionalModel.aspx, Accessed: 01/14/2019.

Interchange Coordinator	IC	Interchange	Ensures communication and coordinates implementation of valid, balanced and confirmed interchanges between balancing authority areas
Resource Planner	RP	Resource Planning	Develops a long-term plan for resource adequacy of specific loads
Planning Coordinator	PC	Planning Reliability	Coordinates, facilitates, integrates and evaluates transmission facility and service plans, and resource plans within its area and coordinates those plans with adjoining areas

Table 1 provides a list of the function names, the names of the functional entities and the responsibilities as have been defined by NERC. Note that the term "long-term" in the high-level summary of the function generally means one year and beyond. Some of these functions are described in greater details later in this section. The NERC Functional Model defines and describes three other functional entities- Standard Developer, Compliance Enforcement Authority, Reliability Assurer and Market Operator, which have not been discussed in detail in this report.

The Reliability Functional Model is not a standard itself but a framework for the development and application of NERC's Reliability Standards. A wealth of information is available from the NERC compliance registry[1] published on their website which lists all the organizations which are registered with NERC for carrying out specific functions from the Functional Model.

3.2.5.1 Interconnections

NERC's area of responsibility comprises four distinct internally synchronous power grids which are referred to as interconnections. These larger network structures provide possible multiple routes for power flow for reliability and commercial purposes. These four interconnections are the Eastern, Western, Texas and Quebec as shown in Figure 8**Error! Reference source not found.**. Hawaii and Alaska's grids are isolated and are not part of any of these interconnections. The interconnections operate largely independently of one another except for limited energy transactions over DC-ties with DC converter substations at each end.

3.2.6 Regional Reliability Entities (RRE)

NERC delegates authority of compliance monitoring and enforcement to RREs and oversees their operations. Members of these RREs come from the different segments of the electric power industry, like federal power agencies, IOUs, Co-ops, Munis, PUDs, IPP, power marketers and end-use customers. Map of these seven RREs and the interconnections they belong to is shown in Figure 8.

[1] NERC, "Organization Registration", Available at: https://www.nerc.com/pa/comp/Pages/Registration.aspx, Accessed: 01/14/2019.

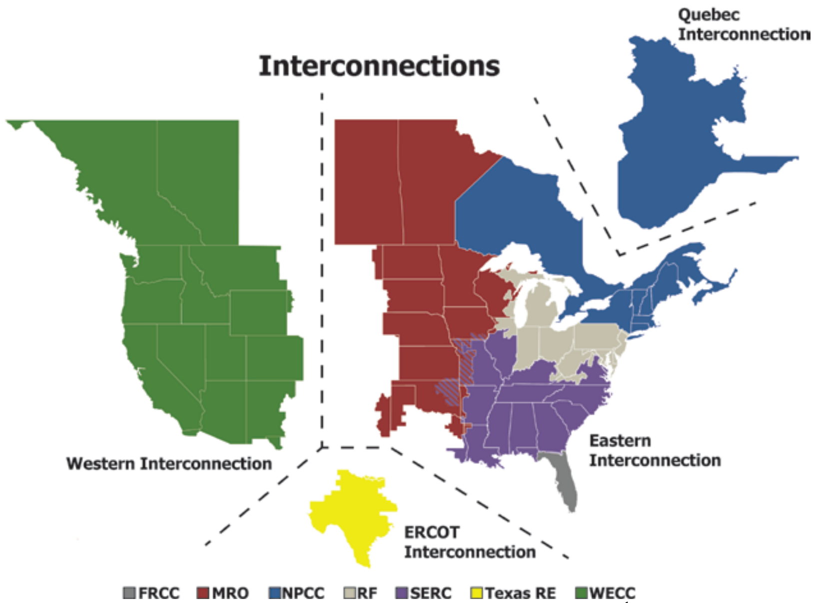

Figure 8: Map showing NERC RREs[1]

The list of the seven regional reliability entities in U.S. are provided in Table 2. It should be noted that there was an eighth RRE called Southwest Power Pool (SPP) Reliability Entity. However, SPP and NERC mutually agreed to terminate this delegation agreement, and the decision was approved by the SPP Board of Directors and endorsed by the SPP Reliability Entity Trustees in 2017[2].

Table 2: List of RREs

Interconnect Name	RRE Full Name	RRE Acronym
Eastern Interconnect	Florida Reliability Coordinating Council	FRCC
	Midwest Reliability Organization	MRO
	Northeast Power Coordinating Council	NPCC
	ReliabilityFirst	RF
	SERC Reliability Corporation	SERC
Texas Interconnect	Texas Reliability Entity	Texas RE
Western Interconnect	Western Electricity Coordinating Council	WECC

3.2.7 Regional Transmission Operator (RTO) and Independent System Operator (ISO)

For enhanced coordination of resources among electrically connected utilities, RTOs or ISOs were created following FERC Orders. RTOs/ISOs are independent, membership-based, non-profit organizations that optimize the wholesale electric market, ensure fair access to the transmission system, and engage in regional transmission planning and expansion. There are no significant distinctions between ISOs and RTOs except that ISOs are prohibited from involving international partners, while RTOs are not[3].

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[1] NERC, “Key Players”, Available at: https://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx, Accessed: 01/10/2019.

[2] D. Wingfield, “Southwest Power Pool to dissolve regional entity, focus on regional transmission organization functions”, Available at: https://www.spp.org/newsroom/press-releases/southwest-power-pool-to-dissolve-regional-entity-focus-on-regional-transmission-organization-functions/, Accessed: 01/13/2019.

[3] N. Vidangos, L. Griffith, F. Flores-Espino and J. McCall, “Electricity in North America: Baseline and Literature Review”, Available at:

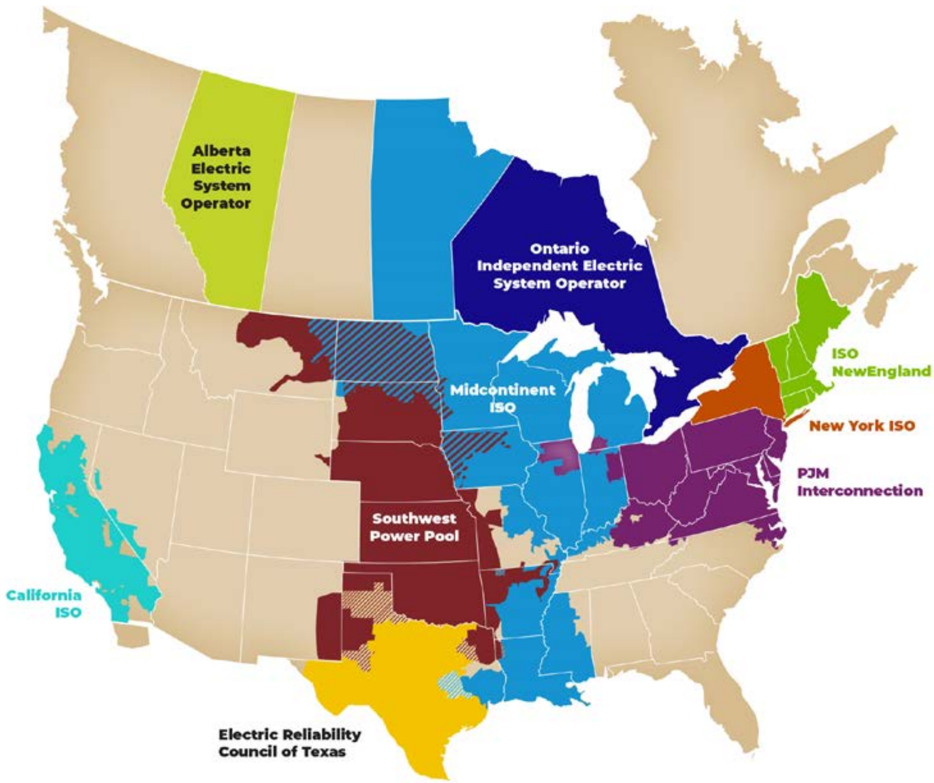

Figure 9: Map showing the RTOs and ISOs[1]

Figure 9 shows the RTOs/ISOs in North America and their areas of service. In areas where there are no RTOs/ISOs, for example in the Southeast and the West parts of U.S., utilities are subject to the same FERC rules and are therefore responsible for serving these functions. It should be noted that unlike the other RTOs and ISOs, ERCOT is overseen by the Texas Public Utility Commission (PUC) and does not fall under FERC authorities for transmission or wholesale market regulation since the ERCOT system is not synchronized with the rest of the U.S. grid. ERCOT, however, is overseen by NERC and is subject to FERC's regulation for reliability[2]. A list of the RTOs/ISOs in U.S. along with information about the RREs overseeing them and the NERC functions that they are registered for are provided in Table 3. There are two other ISOs in North America – Alberta Electric System Operator (AESO) and Independent Electric System Operator (IESO) which are located in Canada.

Table 3: List of RTOs/ISOs in U.S.

Full Name of RTO/ISO	**Acronym**	**ISO / RTO**	**Reliability Entity**	**State Regulators**	**NERC Functions**
California ISO	CAISO	ISO	WECC	California Public Utilities Commission (PUC)	BA, PA, TOP, TSP
Electric Reliability Council of Texas	ERCOT	ISO	TRE	Public Utility Commission of Texas	BA, PA/PC, RC, RP, TOP, TSP

https://www.energy.gov/sites/prod/files/2017/01/f34/Electricity%20in%20North%20America%20Baseline%20and%20Literature%20Review.pdf, Accessed: 01/14/2019.

[1] https://isorto.org/

[2] U.S. DOE Office of Electricity Delivery and Energy Reliability, "United States Electric Industry Primer", DOE/OE-0017, July 2015, Available at: energy.gov/sites/prod/files/2015/12/f28/united-states-electricity-industry-primer.pdf, Accessed: 01/14/2019.

New York Independent System Operator	NYISO	ISO	NPCC	New York State Public Service Commission (PSC)	BA, PA/PC, RC, RP, TOP, TP, TSP
Pennsylvania-New Jersey-Maryland Interconnection	PJM	RTO	RF	State regulatory commissions	BA, PA/PC, RC, RP, TOP, TP, TSP
Southwest Power Pool	SPP	RTO	MRO and SERC	State regulatory commissions	BA, PA/PC, RC, TSP
Independent System Operator New England	ISO-NE	ISO & RTO	NPCC	State regulatory commissions	BA, PA/PC, RC, RP, TOP, TP, TSP
Midcontinent Independent System Operator	MISO	ISO & RTO	MRO and SERC	State Regulatory Commissions	BA, PA/PC, RC, RP, TOP, TP, TSP

3.2.8 Power Market Administration (PMA)

Power Market Administrations (PMA), interchangeably called Power Marketing Agencies, are officially federal agencies within the Department of Energy which market wholesale power produced by federally owned and operated hydroelectric dams. In the U.S. there are four PMAs which operate in total over 33 states. Their names are provided below and a map showing their service territories is provided in Figure 10.

i. Bonneville Power Administration (BPA),
ii. Western Area Power Administration (WAPA),
iii. Southeastern Power Administration (SEPA), and
iv. Southwestern Power Administration (SWPA).

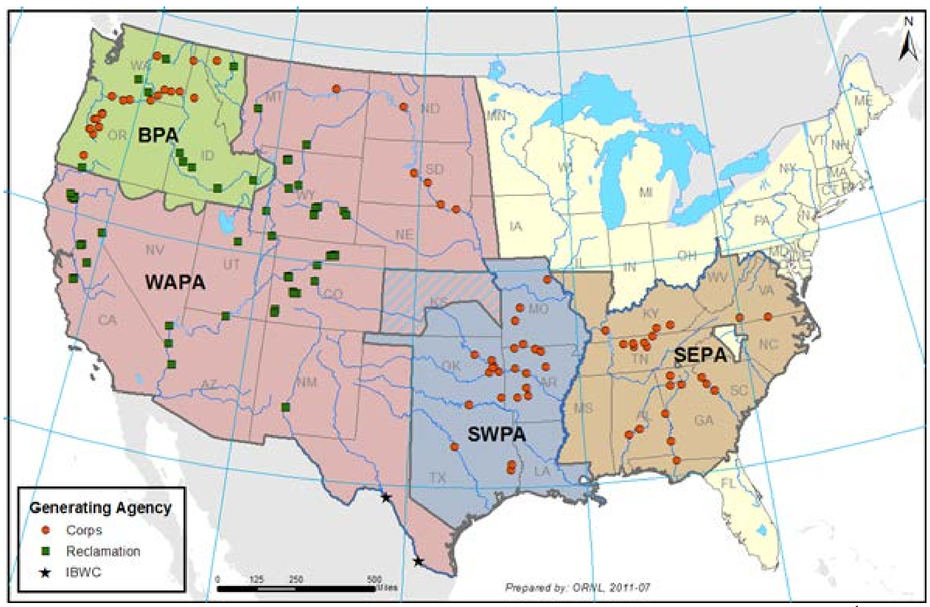

Figure 10: Map showing territories and facilities of the four PMAs[1]

[1] U.S. EIA, "Federal Power Marketing Administrations operate across much of the United States", Available at: https://www.eia.gov/todayinenergy/detail.php?id=11651, Accessed: 01/09/2019.

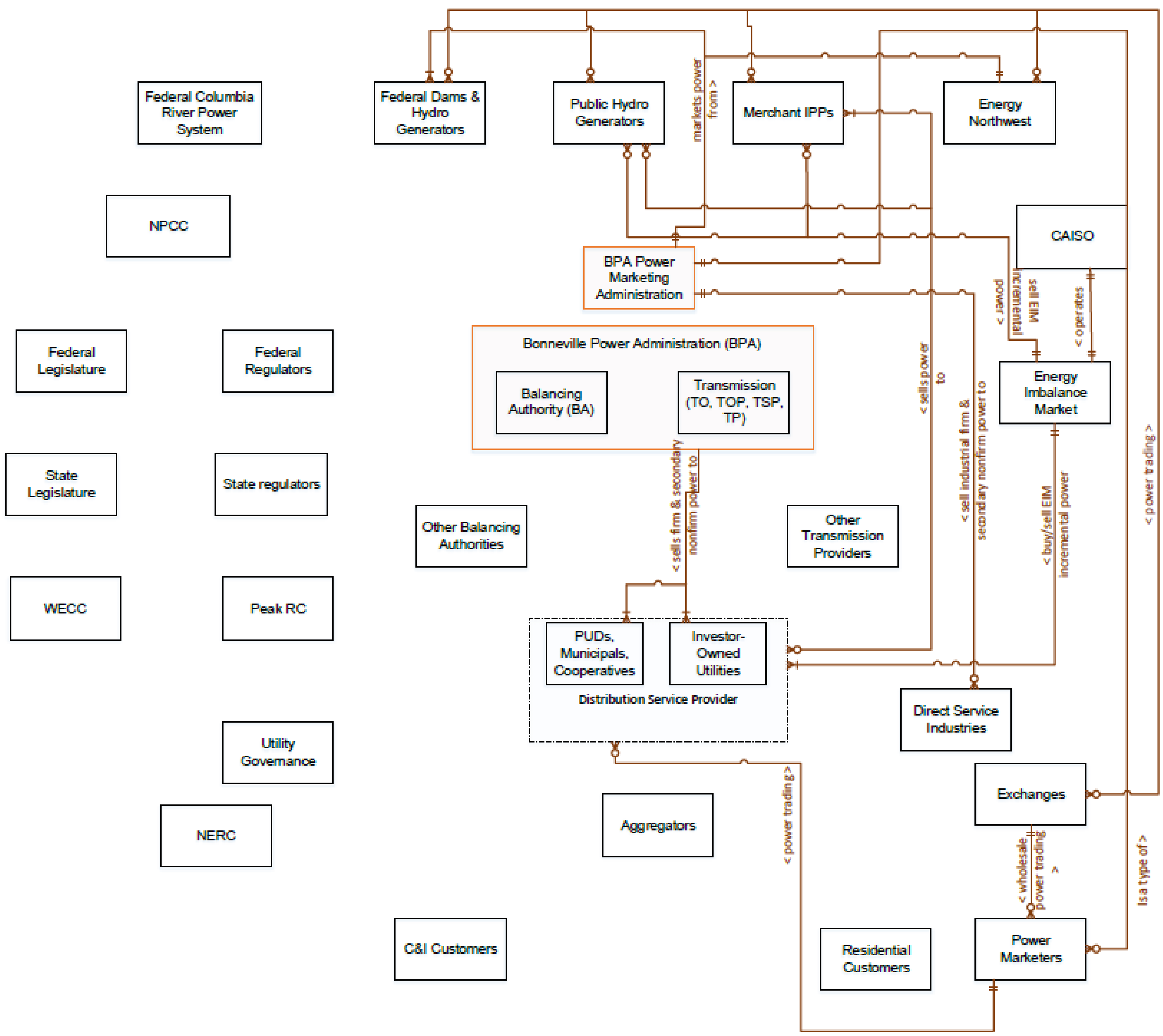

Figure 11: Market interactions in the service territory of BPA

PMAs market most of their power to public utilities and electric cooperatives, also referred to as preference customers, and the rest to Indian tribes, federal entities, IOUs, and some industrial customers. These agencies often fulfill the roles of balancing authority, transmission operator and/or owner. Although they typically do not own generating power plants, in some special cases they have received authority to build and own thermal power plants. Figure 11 shows the function of BPA where it markets electric power from federal hydro power plants in its service territory. BPA also funds the Columbia Generating Station and markets its power although it is owned and operated by the Energy Northwest, and it is a nuclear power plant and not a hydroelectric facility.

Typically, the U.S. Army Corp of Engineers (“Corps”) and the Department of Interior’s Bureau of Reclamation (“Reclamation”) own and operate the hydroelectric facilities which lie within their purview of energy marketing. Some facilities may be owned by the International Boundary and Water Commission (“IBWC”) as indicated on the Figure 10.

3.2.9 Reliability Coordinator (RC)

The reliability coordinator ensures wide-area reliability by developing and monitoring all reliability-related parameters, performing reliability analysis, and directing necessary actions. It also directs and coordinates emergency services and system restorative operations.

An RC receives facility and operational data from GOs, GOPs, TOs, TOPs and LSEs ahead of time. It receives generation dispatch information and integrated operational plans from BAs, and final decision on arranged interchange from the IC, all ahead of time. In the real-time it receives operational information from IC, BA and TOP. Based on its reliability analyses RC issues reliability alerts to GOP, TOP, TSP, BA, IC, RRE and NERC in real-time. It also issues corrective actions and emergency procedure directives to TOP. BA, GOP, DP and IC. Figure 12 shows the hierarchy that is typically followed for monitoring and achieving system reliability. RC coordinates with TOP on system restoration plans, contingency plans and reliability-related services.

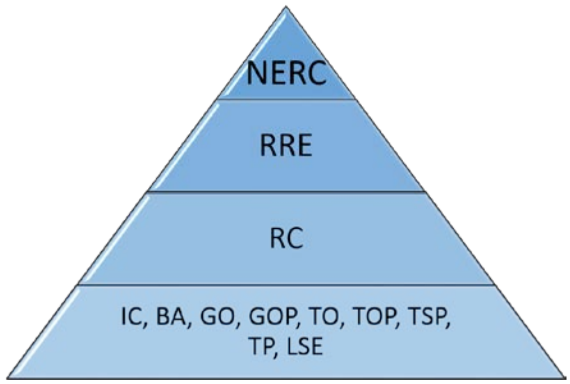

Figure 12: Hierarchy in coordination of reliability

3.2.10 Balancing Authority (BA)

As defined in the NERC Functional Model, BA is the entity which is responsible for maintaining balance between generation, load, and interchange in real-time. Its contribution is critical to maintaining the desired interconnection frequency. On a high-level the tasks of a BA include controlling resources within its area, performing unit commitment (UC) and economic dispatch (ED), deploying regulation service as needed, approving and implementing interchange with adjoining balancing authorities, and providing plans schedules to the RC. During any emergency event, it works with the RC to implement emergency procedures like demand-side management programs, load shedding etc.

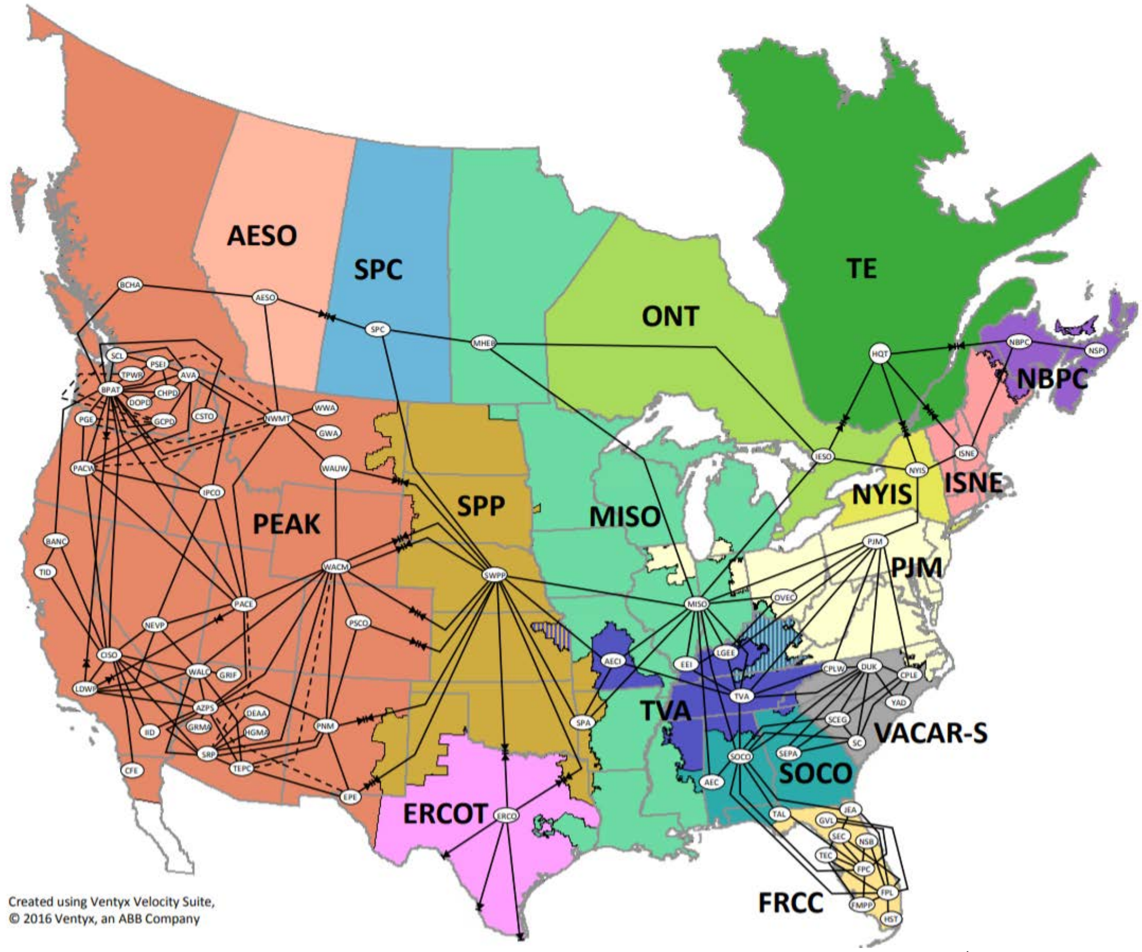

Figure 13: Map showing NERC RCs and BAs as of October 1, 2015[1]

Table 4: Table showing number of RCs and BAs under each NERC RRE[2]

RRE	RC	Number of BAs
MRO	MISO	18
	SPP	
NPCC	ISO-NE	6
	NYISO	
RF	MISO	13
	PJM	
FRCC	FRCC	10
SERC	MISO	23
	PJM	
	Southern Company Services, Inc. - Trans	
	SPP	
	Tennessee Valley Authority (TVA)	
	VACAR South	

[1] NERC, "NERC Balancing Authorities", Available at: https://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/Related%20Files/BA_Bubble_Map_20160427.pdf, Accessed: 01/14/2019.

[2] NERC, "Organization Registration", Available at: https://www.nerc.com/pa/comp/Pages/Registration.aspx, Accessed: 01/09/2019.

SPP	MISO	6
	SPP	
TRE	ERCOT	1
WECC	Peak Reliability	34

The Texas Interconnect consists of only one BA, which is the ERCOT. A map of the different organizations which are registered with NERC to serve as RCs are shown in Figure 13Figure 13. A list of the RCs, the RRE under which they are assigned, and the number of BAs they manage is provided in Table 4.

3.2.11 Electric Utilities

The U.S. EIA defines utilities as "a corporation, person, agency, authority, or other legal entity or instrumentality aligned with distribution facilities for delivery of electric energy for use primarily by the public." Utilities can be of the following types depending on the ownership:

- IOUs: These are for-profit private companies whose stock is publicly traded. It is subject to rate regulation by state public utility/service commissions[1]. IOUs serve about 75% of the US population[2].
- City-owned or Municipal utilities (Munis): These are not-for-profit electric utilities owned by the city council or other elected commission. They are generally governed by their own local government and are not subject to federal or state regulations.
- Cooperatives (Co-ops): These are not-for-profit electric utilities governed by a board of representatives elected by the customers. Co-ops mostly serve in rural areas where historically IOUs were unwilling to serve, but there are some urban co-ops as well. Rates are set to recover costs, with margin for replacement.
- Public Utility Districts (PUDs): A PUD is a body of local government providing essential services like electric, water, sewer or telecommunication services within a specified area at a rate which is based on the actual cost of providing service[3]. It is owned and operated by the people they serve, and the governing board is formed by a vote of the people who live within the service territory.
- Others: These include Native American tribes, mutual power associations and other entities which provide electric service in few parts of the U.S[2].

Table 5: High-level characteristics of different types of utilities based on 2017 data of U.S. EIA[4]

Type	**Number of Utilities**	**Revenue**	**Rates Set by**	**Infrastructure**

[1] U.S. EIA, "Glossary", Available at: https://www.eia.gov/tools/glossary/index.php?id=electricity, Accessed: 01/14/2019.

[2] Jim Lazar, with RAP Staff, "Electricity Regulation in the US: A Guide", 2nd Ed., Available at: http://www.raponline.org/wp-content/uploads/2016/07/rap-lazar-electricity-regulation-US-june-2016.pdf, Accessed: 01/08/2019.

[3] Tillamook PUD, "What is a PUD", Available at: https://www.tpud.org/aboutus/what-is-a-pud/, Accessed: 01/12/2019.

[4] U.S. EIA, "Electric power sales, revenue, and energy efficiency Form EIA-861 detailed data files", Available at: https://www.eia.gov/electricity/data/eia861/, Accessed: 01/14/2019.

IOU	171	For-profit	State public utility/service commissions	Typically owns generation, transmission, and distribution systems
Municipals	829	Nonprofit	City council or elected commission or governing board	Primarily owns distribution, may own some generation
Cooperatives	808	Nonprofit	Governing board	Primarily owns distribution with some generation and transmission
Political Subdivisions (PUDs)	101	Nonprofit	Publicly elected board of commissioners	Most own distribution, with some owning generation and transmission too

3.2.12 Generator Operator (GOP)

A GOP formulates UC plans and operates the generation facilities in order to provide power (both real and reactive power) and reliability-related services. It monitors the status of the generating units and related equipment and reports their operating and availability status to BA and TOP. A GO may also serve as the GOP, or a separate organization may be designated to operate the facilities.

3.2.13 Independent Power Producer (IPP)

The IPP entity class consists of non-utility generators, or in other words, generators that are typically not owned at the utility company. The utility company which has control over the transmission and distribution system may buy entire or surplus power from IPPs which are connected to the system. An IPP may also sell electricity and sometimes heat to customers via private wires.

3.2.14 Transmission Operator (TOP)

A TOP operates the transmission facilities within its purview and ensures real-time operating reliability within its area of service. A TOP monitors the status of and deploys transmission assets (like transmission lines, protection systems) and reactive resources, adjusts flow control devices, and provides telemetry. It also develops system limitations and operates its system within the specified limits. Development and implementation of emergency procedures as well as system restoration plans are also performed by TOP.

3.2.15 Transmission Service Provider (TSP)

A TSP processes transmission service requests received from GOs, LSEs and PSEs. The TO’s tariff and the operating limits provided by the RC are considered when processing such requests. A TSP also allocates transmission losses between the BAs and arranges for transmission loss compensation.

3.2.15.1 OASIS

As part of deregulation of electric power and the creation of the current systems a need for non-discriminatory access to transmission systems for delivery of power under contract was needed. A system referred to as OASIS was created for this purpose. OASIS is operated by the company Open Access Technology, Inc. (OATI.) OATI is responsible for a reservation process in which “tickets” are purchased to reserve the right to send a certain amount of energy through a specific transmission system corridor. Tickets may be purchased independent of power contracts. Thus, there is a market in trading tickets in addition to trading power. For power to be delivered both a power contract and a transmission system reservation are required. ISO / RTO implements equivalent functionality in case it does not use OASIS.

3.2.16 Direct Service Industries

Direct service industries are industrial customers who purchase power directly from the transmission provider instead of buying from a utility. For example, the BPA sells a small portion of the electrical power produced at the 31 federal dams and the Columbia Generating Station in its area to some industries in the northwest[1]. In fact, access to the relatively cheap Columbia River hydroelectric power gave rise to the Northwest's significant aluminum smelting industry. Typically, direct service industries include aluminum plants, paper mills, pulp mills and chemical manufacturers.

3.2.17 Wholesale Market Operator

The wholesale energy market is the entity class which plays the central role in the buying and reselling of wholesale power between the suppliers and the resellers (includes utilities, LSEs and power marketers). In the regions which have regional RTOs or ISOs, they provide open access to the transmission systems and administer the wholesale electricity markets. These organized wholesale electricity markets serve about two-thirds of the U.S. population[2]. There are FERC rules, sometimes referred to as “firewalls”, designed to prevent market manipulations from operation of the transmission system. Except for ERCOT, the operations and transactions of these wholesale markets are overseen by the FERC. Transactions may also take place based on bilateral contracts in these regions in compliance with the RTO/ISO rules.

3.2.18 Independent Market Monitor (IMM)

IMM is an organization that provides impartial market monitoring services for the wholesale electricity market. Their responsibilities include monitoring of compliance with market rules, developing metrics and tools for analysis, evaluating the market performance, identifying and investigating anti-competitive behavior, collecting data and preparing reports. A list of the organizations which serve as Market Monitors for the different RTOs and ISOs is provided in Table 6, and whether these organizations are independent of or internal to the specific RTO/ISO it is overseeing has been indicated.

Table 6: IMM overseeing market performance of RTOs and ISOs

RTO/ISO	Internal/Independent	Performed by
CAISO	Internal	Department of Market Monitoring (DMM)
ERCOT	Independent	Potomac Economics
ISO-NE	Independent	Potomac Economics
MISO	Independent	Potomac Economics
NYISO	Independent	Potomac Economics
PJM	Independent	Monitoring Analytics
SPP	Internal	SPP Market Monitor

3.2.19 Energy Imbalance Market (EIM)

CAISO operates the EIM which allows the participating BAs to pool their resources in this voluntary sub-hourly real-time energy market in order to achieve balance between electricity supply and demand over a wider area. This region-wide generation dispatch helps to moderate the variability caused by renewable generation such as wind and solar, and also reduces the reserve requirements[3].

[1] https://www.nwcouncil.org/reports/columbia-river-history/directserviceindustries
[2] “The Future of the Electric Grid: An Interdisciplinary MIT Study”, Available: http://web.mit.edu/mitei/research/studies/the-electric-grid-2011.shtml
[3] https://www.nrel.gov/docs/fy12osti/56236.pdf

3.2.20 Exchanges

Exchanges are the energy market places for trading electricity as a commodity. They allow longer term hedging than the Day-Ahead Market (DAM) and Real-Time Markets (RTM) which allow hedging of only up to maximum of 24 hours in advance of the operating period. In order to protect against price volatility of wholesale electricity, market participants take resort to longer-dated hedges in other markets such as Nodal Exchange, Intercontinental Exchange (ICE) or New York Mercantile Exchange (NYMEX). The two parties, i.e. the buyer and the seller, can also arrange a bilateral agreement. Futures contracts are traded on the NYMEX which allows generators, power marketers and end-users to hedge against unexpected price fluctuations. Over the Counter (OTC) energy market operated by Intercontinental ICE also provides bilateral contracts for utilities to settle at a guaranteed price for electricity, and therefore minimize financial risks associated with electrical energy production. The exchanges publish spot market prices for various supply or delivery points in the electric power system. For example, there is a Mid-C price index for the power sold by the dams on the Columbia River owned by some of the PUDs in the State of Washington. Power exchanges are points of arbitrage and present an opportunity for resources capable of load shifting, such as battery storage systems, to earn revenue by buying power when prices are low and reselling when they are high.

3.2.21 Power Marketers

Power marketers form another entity class that is important when talking about wholesale electric power. Power Marketers usually own or control generation or transmission facilities but act as intermediaries by purchasing electricity from numerous utilities and reselling it to other utilities or distribution providers. By taking advantage of the disparities in prices and determining their best combination, they can provide better prices to their customers while making a profit for themselves. Registration with the FERC is necessary to obtain status as a power marketer.

Unlike power marketers, power brokers serve as middleman between the buyer and seller by consulting and helping negotiate the details of the contracts, but they do not take ownership of the electricity.

3.2.22 Load Serving Entities (LSE)

The entities described above deal with wholesale energy management and transactions. It is equally important to look at the retail side of the industry. An LSE is an organization which arranges energy and transmission services to serve the end-use customers, but it may or may not serve as a distribution provider (which provides the “wires” services). In ERCOT region, LSEs include Competitive Retailers (CRs) and Non-Opt-In Entities (NOIEs). CRs are Munis or Co-ops which opt to offer customer choice (i.e. allows customer to choose Retail Electric Provider), while NOIEs are Munis or Co-ops which do not offer customer choice.

U.S. EIA breaks down retail electricity sales into four major sectors:

- Residential customers
- Commercial customers
- Industrial customers
- Transportation

Figure 14 shows the percentage of retail electricity that was consumed by the four customer sectors based on U.S. EIA's 2017 data. For the purpose of our industry structure diagrams we have aggregated the commercial and industrial customers into a single entity class referred to as the Commercial and Industrial (i.e. C&I) consumers. Entity class representing transportation customers has been shown only in regions where utilities reportedly handle significant transportation-based electric load.

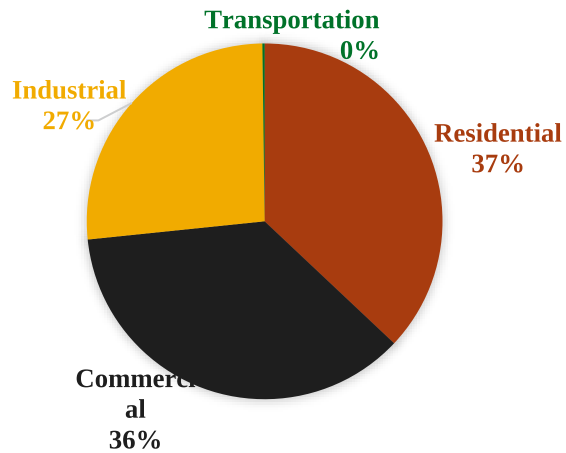

Figure 14: Retail electricity use by sector for year 2017

3.2.23 Purchasing-Selling Entities (PSE)

A PSE purchases or sells, or takes title to energy, capacity or reliability-products that it secures from a resource and arranges to get it delivered to an LSE. As part of its service, it arranges for transmission service and initiates bilateral energy transaction between BAs.

3.2.24 Residential Customers

Residential customers include single-family homes and multi-family housing. The increase of residential on-site PV generation will decrease the amount of electric energy purchased from the grid. Increased adoption of electronic devices is expected, but due to the use of more energy-efficient lighting and equipment the average electricity consumption per household is predicted to decrease in the future.

3.2.25 Commercial and Industrial Customers

The commercial sector includes retail, office, institutional, public and government facilities, and public services. Industrial customers, on the other hand, include manufacturing, mining, agriculture and construction industries.

3.2.26 Transportation

The transportation sector includes subway, electric rails, plug-in hybrid electric vehicles and all-electric vehicles which use electric power from the grid. Currently this sector uses less than 1% of the total retail electricity in U.S. However, with the increased adoption of electric vehicles this percentage is predicted to increase in the future.

3.2.27 Aggregators

An aggregator acts as a middleman between utility and users and can negotiate with the utility on behalf of the customers. They may provide technology for performing Demand Response (DR) or better management of DER. Note that the DER aggregator business model has essentially failed and this class of entity as a private sector Energy Services Organization is disappearing in the U.S. This is due to the low value of grid services and the high cost of acquiring customers for the aggregator service. The use of DER for Non-Wires Alternatives (NWA) is also failing since the values and available revenues do not support the DER investment. Also, partial avoidance of an asset build is not feasible and simply delaying an asset build does not actually avoid the cost In the meantime, if DER assets are being used for NWA and these assets become unavailable (which can happen for many reasons since the DER owners and operators do not have an obligation to serve as the utilities do), the utility has no backup way to avoid the resultant reliability problem.

3.2.27.1 Community Choice Aggregation (CCA)

Community Choice Aggregators (CCA) are administered by the local government. They are responsible for aggregating the electrical loads (e.g. residents, businesses and municipal facilities) within their area of service and purchasing electrical energy on their behalf. The incumbent IOUs in the service region continue to provide distribution, transmission, and administrative services to the customers. Typically, customers located within the service area of a CCA program are automatically enrolled in program, unless they elect to opt-out, in which case the IOUs provide power to these customers directly.[1]

3.2.28 Industry Summary Statistics and Considerations

This section of the PDR documents some features of electric power systems that don't seem to fit anywhere else in the discussion but that may be useful to consider in the development of the reference architectures.

3.2.28.1 Industry Business Models

In the U.S. there are a variety of utility business models depending on the region of the country, whether or not there are structured markets in that region, and the nature of the utility business model and ownership. These considerations are summarized looking at business structure and business ownership.

Business Structure

Business structure refers to the scope and function of the utility business as it relates to the generation, transmission, distribution and sale of electricity. Historically utilities provided service within their territory encompassing everything from generation to end-use. This structure is often referred to as "vertically integrated" and utilities of this type continue to exist.

[1] B. Mow, "Community Choice Aggregation (CCA) Helping Communities Reach Renewable Energy Goals", Available at: https://www.nrel.gov/state-local-tribal/blog/posts/community-choice-aggregation-cca-helping-communities-reach-renewable-energy-goals.html, Accessed: 01/08/2019.

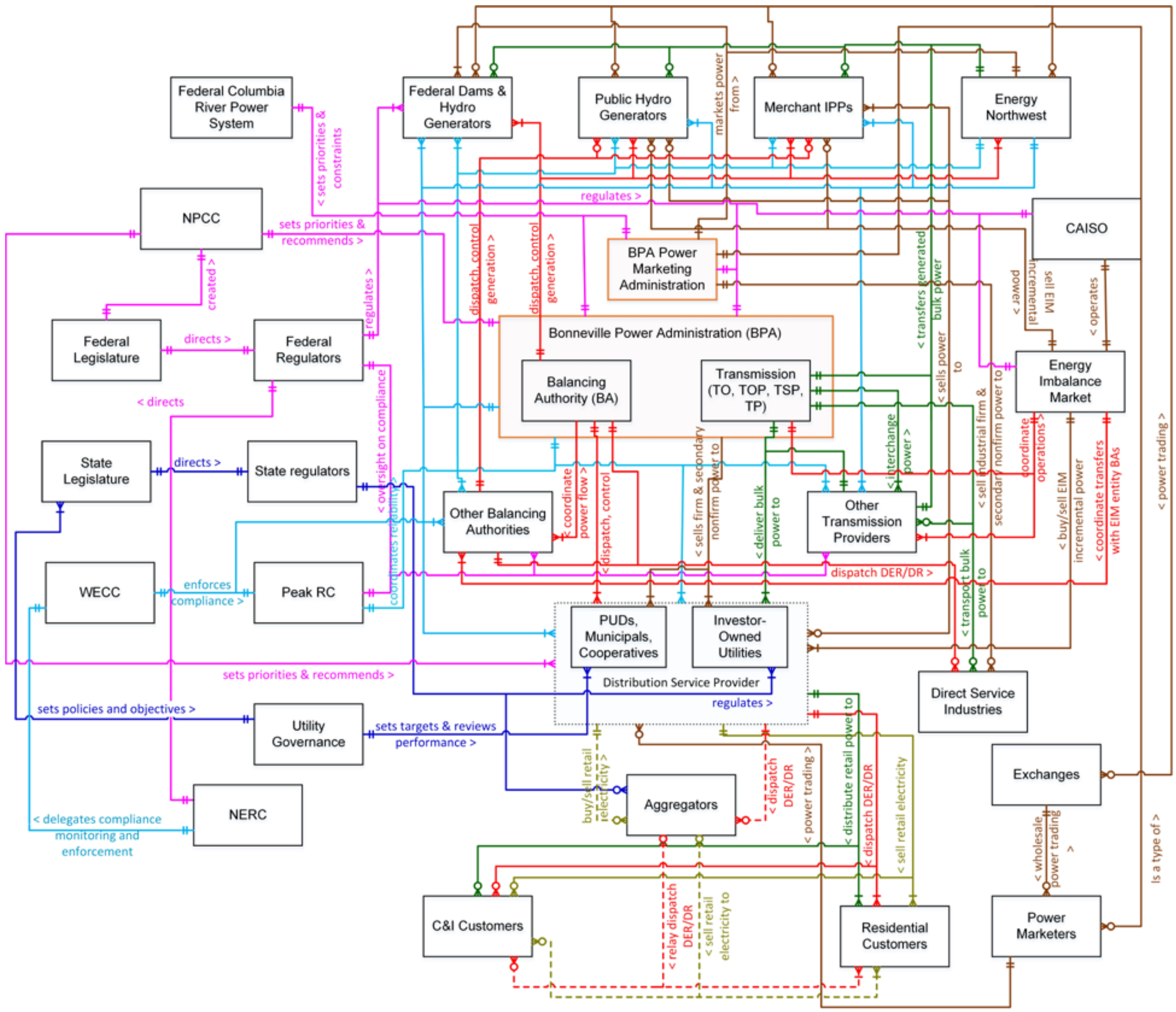

Figure 15: Industry Structure diagram of the Pacific Northwest region showing the NERC functions as separate entities

With the constituent elements of generation, transmission, distribution, and sales broken out there are examples of businesses representing each element in isolation or pairs of elements including generation and transmission, and distribution and sales.

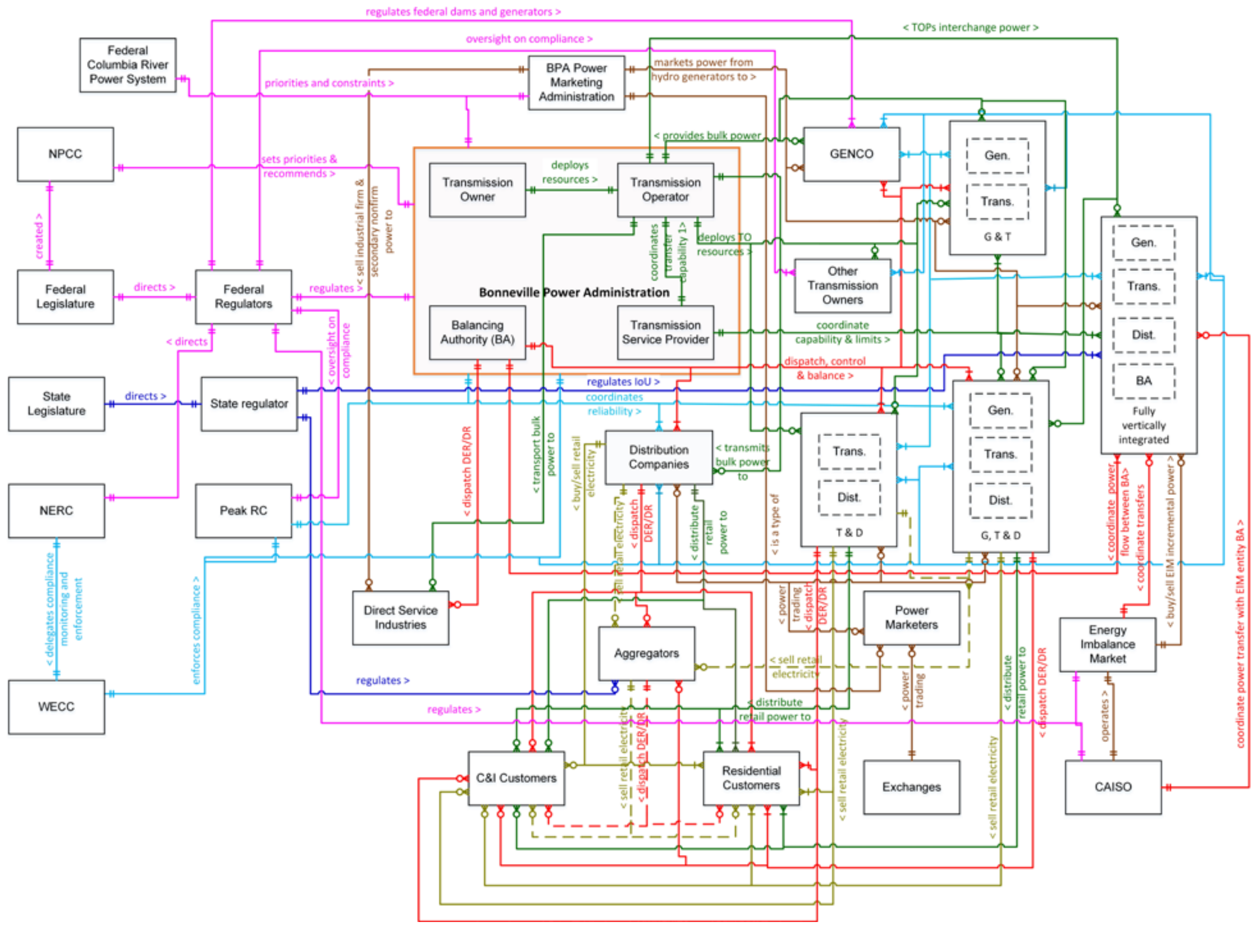

Figure 16: Industry Structure diagram of the Pacific Northwest region showing the different business structures existing among the utilities

When considering any of these business models one generally encounters the notions of "natural monopoly" and the "regulatory compact." Early in the history of the electric power industry it was recognized that the incremental cost of adding new customers was such that it was not cost effective to have competing physical infrastructure. The notion of the electric power industry as a natural monopoly serving the public good led to the development of the regulatory constructs described elsewhere in the PDR. Further details may be found in any number of books on the economics of the electric power system. For the purposes of the PDR it is important to note that with growing penetrations of DER there are third-party businesses providing services to end-users of electricity outside of the regulatory construct. These third-party businesses are seen by some as a threat to existing utilities and their business models. One response to this situation is a growing consideration by utilities to shift their businesses from selling the commodity of electric power to providing a variety of services related to electric power.

In addition to these structural considerations and the regulatory construct are the ownership models of utilities. These range from IOUs that are subject to regulation by state or federal entities to various forms of publicly owned utilities including Munis, PUDs, and Co-ops. Each of these is also regulated either by elected officials in the form of city councils or boards of public utility commissioners, or by boards of member-owners elected from the Co-op members.

Figure 15 and

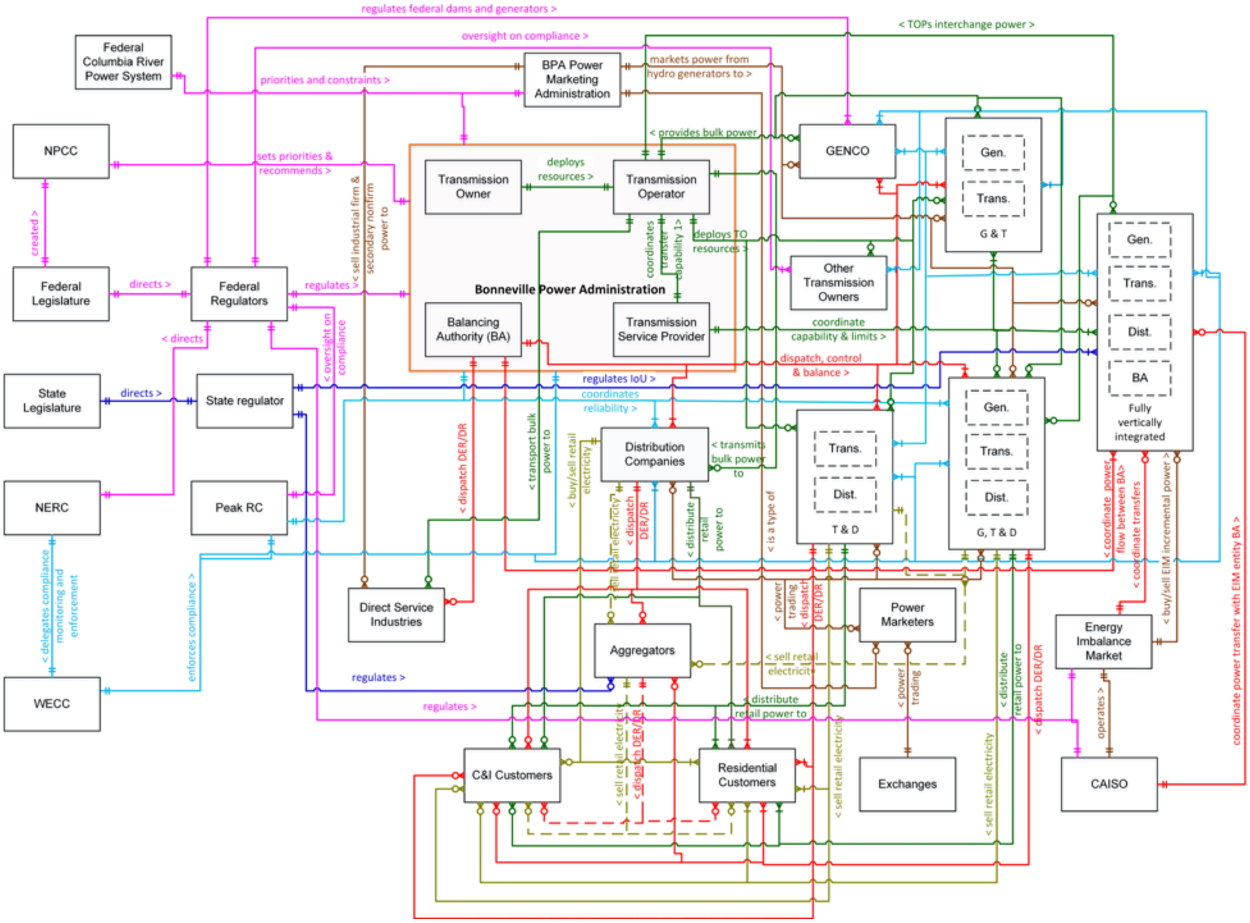

Figure 16 show two different versions of the Industry Structure diagram of the Pacific Northwest region with the former showing the NERC functions as different entity classes and the latter categorizing the utilities based on their business structures.

4.0 Functional Groups in Industry Structures

The Industry Structure diagrams depict the functional relationships between the entity classes which are the key players in the electric power industry of any region. They are prepared starting with the information provided in Section 3.2, after which details specific to the region's electric power industry are collected, analyzed and added to accurately represent the structure. This section of the PDR decomposes the electric power system into seven major functional groups as follows:

i. Federal Regulation,
ii. State Regulation,
iii. Market Interaction,
iv. Retail,
v. Reliability Coordination,
vi. Energy and Services, and
vii. Control and Coordination.

4.1 Types of Functions

The functional groups are represented in the same diagram in the form of different layers. The type of the function can be identified by the color of the line and its text descriptor. The colors that have been used for the different functions and have been shown in Figure 17 and is typically used as legend in the Industry Structure diagrams.

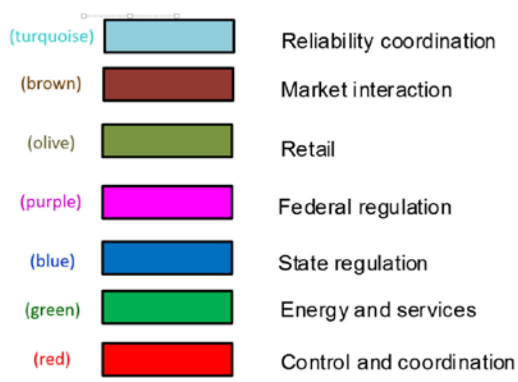

Figure 17: Colors representing different functions

It should be noted that in the multi-layer Industry Structure diagrams each layer can be turned on or off to decompose the complexity of the structure and better understand the individual functional groups. Figure 18 shows one version of the Industry Structure of the Pacific Northwest region where the entity classes representing the different utilities have been categorized based on their business structures (e.g. G&T, T&D etc.). In this figure all layers have been turned on to provide an idea regarding the level of complexity of such a system.

The figures showing the different functional groups that have been provided later in this report typically show only the connected portion of the diagrams, and omit the entities that are not part of those specific groups, in order to be able zoom into the area of focus.

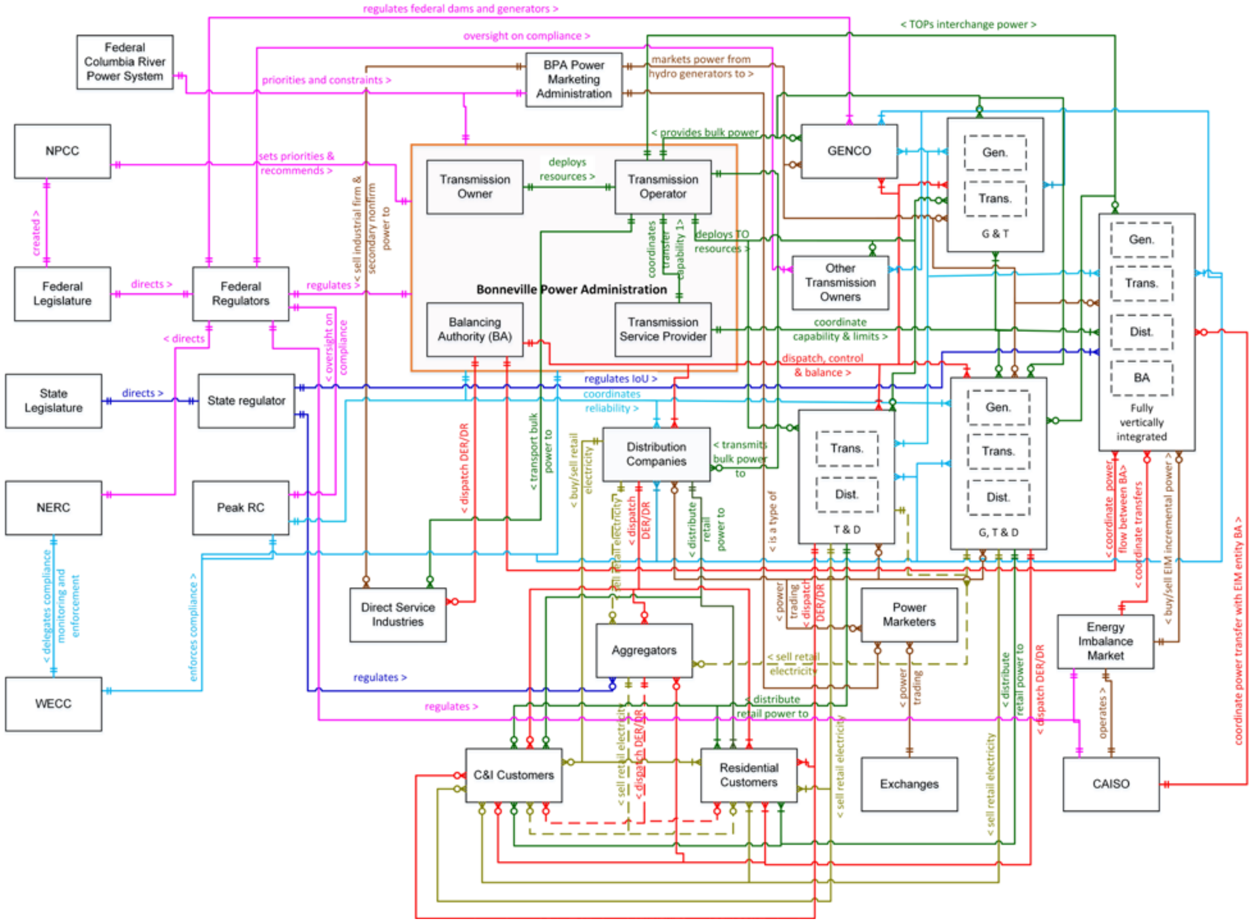

Figure 18: Integrated version of Industry Structure diagram of the Pacific Northwest

In addition, specific individual diagrams have been prepared, in some cases in greater detail than the industry structure diagrams, to represent specific functional elements. These include market structure diagrams which incorporate details on the functional and temporal relationship between markets and control and coordination in a region. There is also a “Regulatory Structure Model for the United States Electric Sector” that provides an integrated view of the structural complexity of the relationships between legislative, regulatory, and operating entities.

4.2 Federal Regulation

The Federal Regulation functional group of the Industry Structure diagram represents the entities and relationships in the context of federal regulation. The federal regulations are written by the executive agencies and provide detailed instructions regarding how the responsible agencies should enforce the statutes passed by the Congress. FERC is the federal agency which serves as the principal federal regulator and uses legislative-style rulemaking and hearings processes[1]. FERC regulates wholesale sales and transmission of electricity in interstate commerce, and non-federal hydropower projects. Federal policies and regulations play an important role in shaping investment decisions. For example, Figure 19 shows some of the significant federal policies overlaid with the energy generation resources in use in the U.S. over time. It is evident that these policies influenced the resource mix after they came into effect.

[1] Jim Lazar, with RAP Staff, “Electricity Regulation in the US: A Guide”, 2nd Ed., Available at: http://www.raponline.org/wp-content/uploads/2016/07/rap-lazar-electricity-regulation-US-june-2016.pdf, Accessed: 01/08/2019.

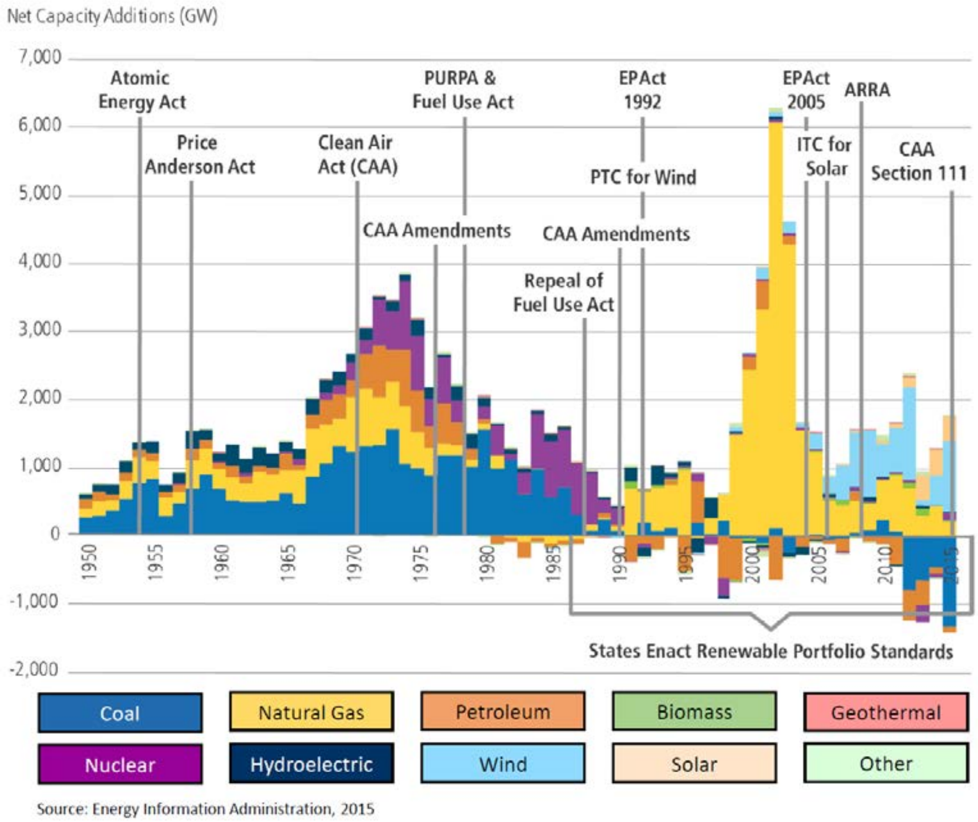

Figure 19: Impact of federal policies on generation mixes[1]

In 2006, FERC certified NERC as the Electric Reliability Organization (ERO) of the nation and delegated the authority to develop and enforce compliance of reliability standards. However, FERC reviews and audits the operations of NERC. With approval of FERC, in the U.S. seven RREs have been delegated authorities and responsibilities by NERC to enforce compliance and regional reliability standards and perform standards-based functions. In Figure 20 it is seen that WECC enforces compliance in the considered region.

The U.S. federal government is the largest owner of electricity generating capacity and owns significant transmission assets, for example hydroelectric projects are owned by federal agencies like the U.S. Army Corps of Engineers (Corps), Bureau of Reclamation (Reclamation), Tennessee Valley Authority (TVA), Bureau of Indian Affairs, and the International Boundary and Water Commission. Wholesale power from these federal hydropower projects as well as from the Columbia Nuclear Generating Station are generally marketed by the four PMAs. On one hand the PMAs receive some financial support from the U.S. Government; on the other hand FERC regulates PMA rates in order to ensure that money borrowed from the U.S. Treasury can be repaid on schedule.

In case of non-federal hydropower plants, FERC licenses their construction and operations, and also oversees safety of the dams[2]. Since there are limited or no interstate transmissions in Texas, Alaska and Hawaii, only hydropower regulation is overseen by FERC.

[1] Quadrennial Energy Review (QER) Task Force “Quadrennial Energy Review: Second Installment” Jan 2017, Washington D.C., Available at: https://www.energy.gov/policy/initiatives/quadrennial-energy-review-qer/quadrennial-energy-review-second-installment, Accessed: 01/14/2019.

[2] U.S. EIA, “Federal Power Marketing Administrations operate across much of the United States”, Available at: https://www.eia.gov/todayinenergy/detail.php?id=11651, Accessed: 01/12/2019.

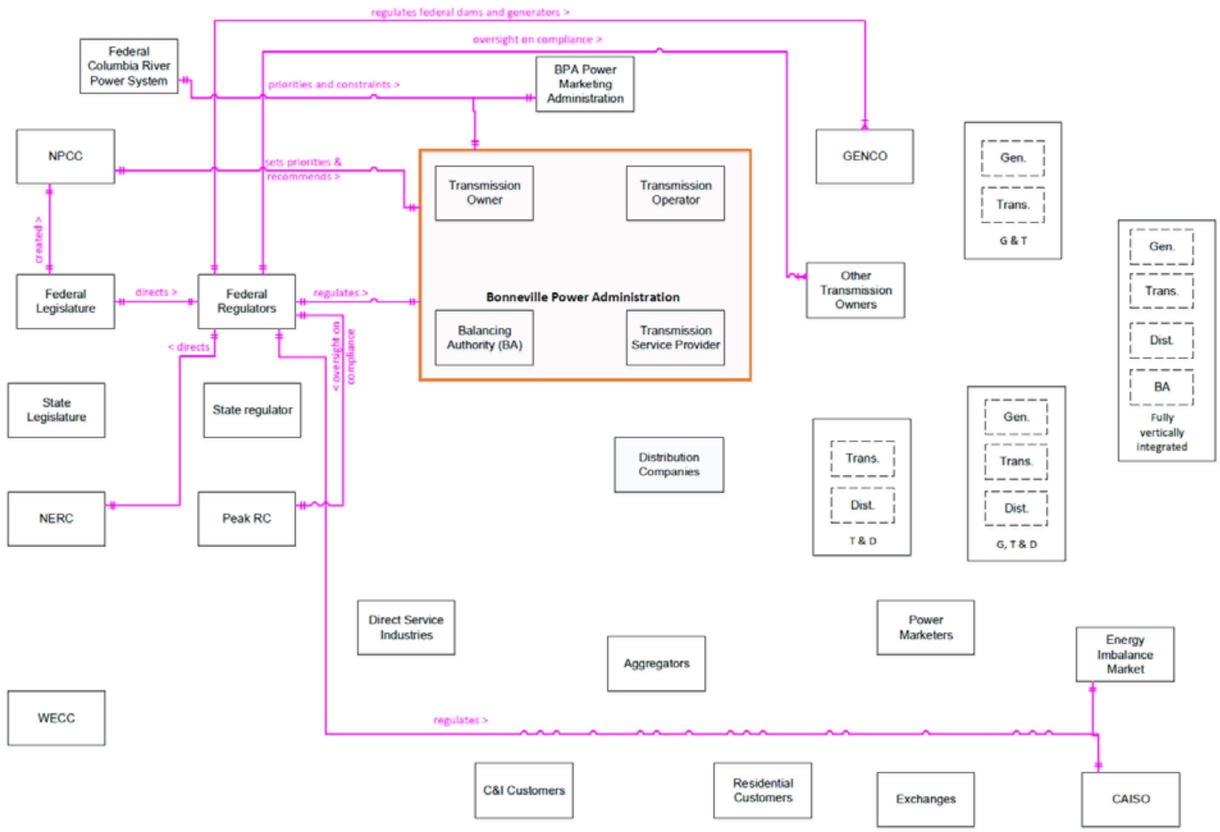

Figure 20: Federal Regulation functional group for Pacific Northwest region

4.3 State Regulation

The Federal Power Act established a “bright line” dividing federal and state regulation by using factors such as transaction and customer type (wholesale vs retail), facility type (generation vs transmission vs distribution), geography (interstate commerce vs intrastate commerce), and regulatory action (e.g., rate regulation vs facility permitting)[1]. The principal function of state commissions consists of determining a utility’s revenue requirement and establishing the rates for each customer category. Retail rates are generally regulated by states using a process that varies depending on the type of regulatory oversight the utility is subject to. The state regulatory commission generally regulates all the IOUs in its state, and in about 20 states cooperatives are also regulated in some form[2]. IOUs operate for the public good and are allowed to recover costs and a negotiated profit, usually around 6%.

State agencies are also responsible for issuance of permits which are required to construct and operate generation and transmission assets. Since ERCOT service territory lies entirely within the state of Texas, the Public Utility Commission of Texas (PUCT) has regulatory authority over the transmission and wholesale market operations of the region, unlike in the case of other ISOs where FERC typically has this authority. Figure 21 shows the State Regulation functional group for the region served by ERCOT.

[1] J. Dennis, S. Kelly, R. Nordhaus and D. Smith, “Federal/State Jurisdictional Split: Implications for Emerging Electricity Technologies, LBNL-1006675, Available at: https://www.energy.gov/sites/prod/files/2017/01/f34/Federal%20State%20Jurisdictional%20Split--Implications%20for%20Emerging%20Electricity%20Technologies.pdf, Accessed: 01/14/2019.

[2] J. Lazar with RAP Staff, “Electricity Regulation in the U.S.: A Guide”, 2nd Ed., Available at: https://www.raponline.org/wp-content/uploads/2016/07/rap-lazar-electricity-regulation-US-june-2016.pdf, Accessed: 01/14/2019.

In many states, energy portfolio standards are adopted by the state legislators or commissions which requires the utilities to meet a certain percentage of their energy supply from a defined set of renewable resources. Figure 22 shows how the renewable portfolio standards for the different states in U.S. are different, and this difference can be attributed to the different standards adopted by them.

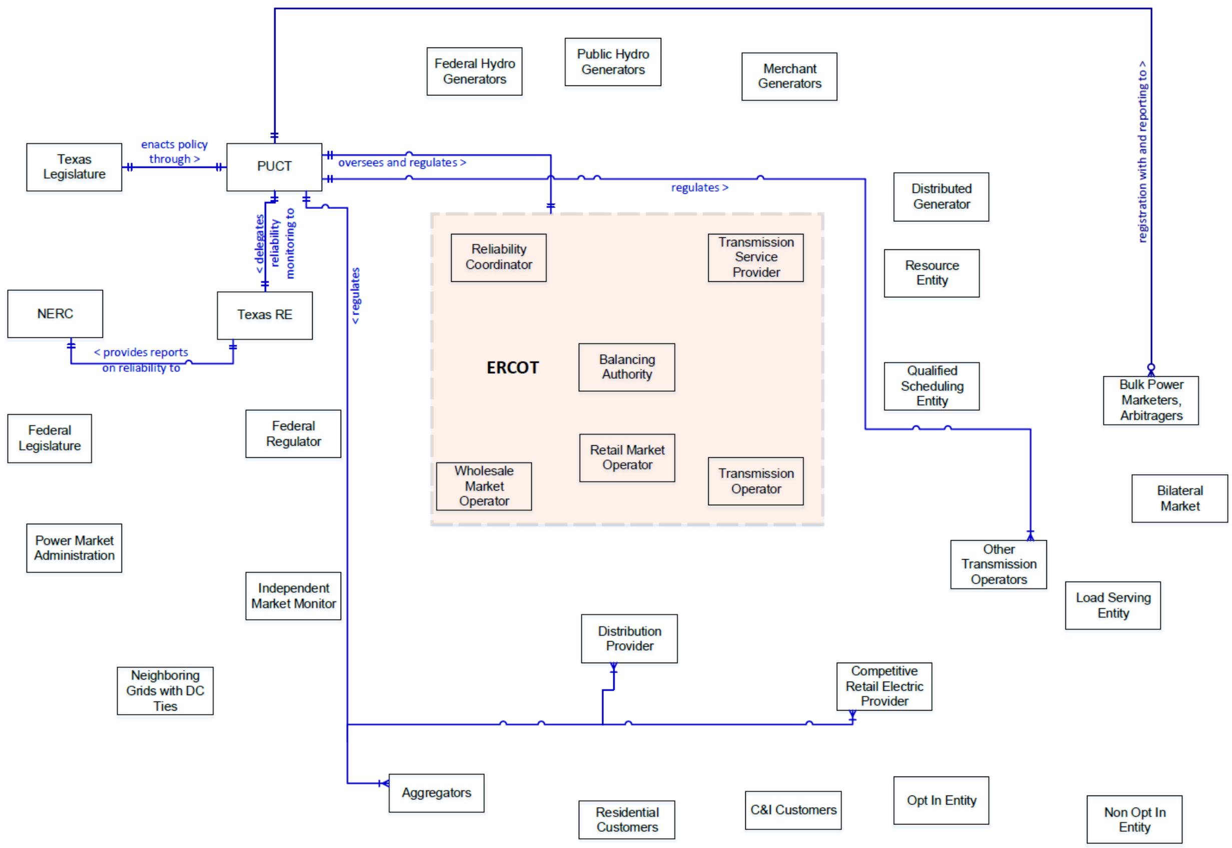

Figure 21: State Regulatory functional group for the region served by ERCOT

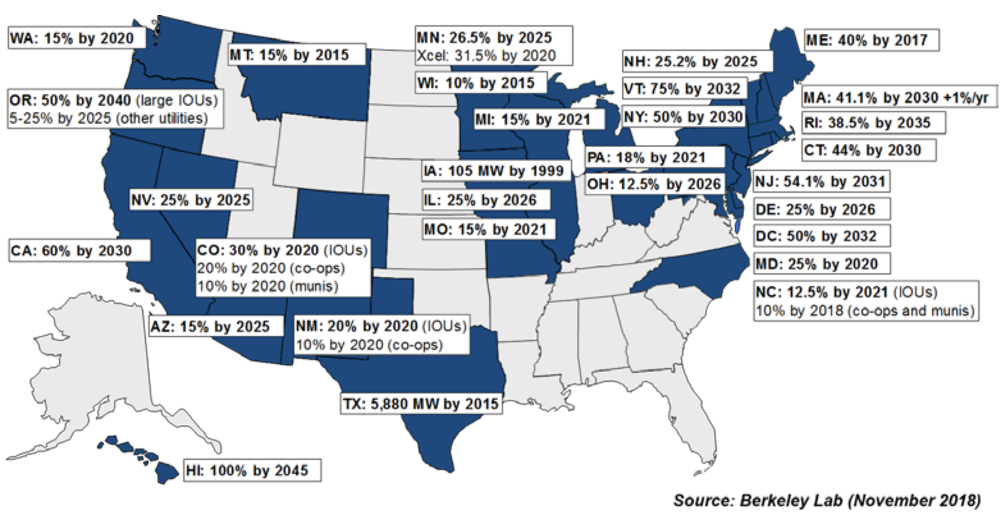

Figure 22: Renewable portfolio standards of different states in the U.S.[1]

[1] https://emp.lbl.gov/projects/renewables-portfolio

4.3.1 Regulatory Structure

Regulatory bodies are created by the legislative branch of the government and have been vested with specific powers by the Congress or the state legislatures. The authorities for regulating and overseeing the electric power industry spans federal, state, local, and tribal levels. For better understanding the combined federal and state regulatory structures are represented in the "Regulatory Structure Diagram" as shown in Figure 23. It depicts what entities are regulated, what entities are regulators and the nature of the regulatory relationship.

Although the Federal Power Act had established a division between federal and state regulation based on several factors, in recent years this division is becoming increasingly indistinct with the adoption of new technologies that result in two-way flow of electric power between the transmission and distribution systems[1].

Regulatory Structure Model for United States Electric Sector

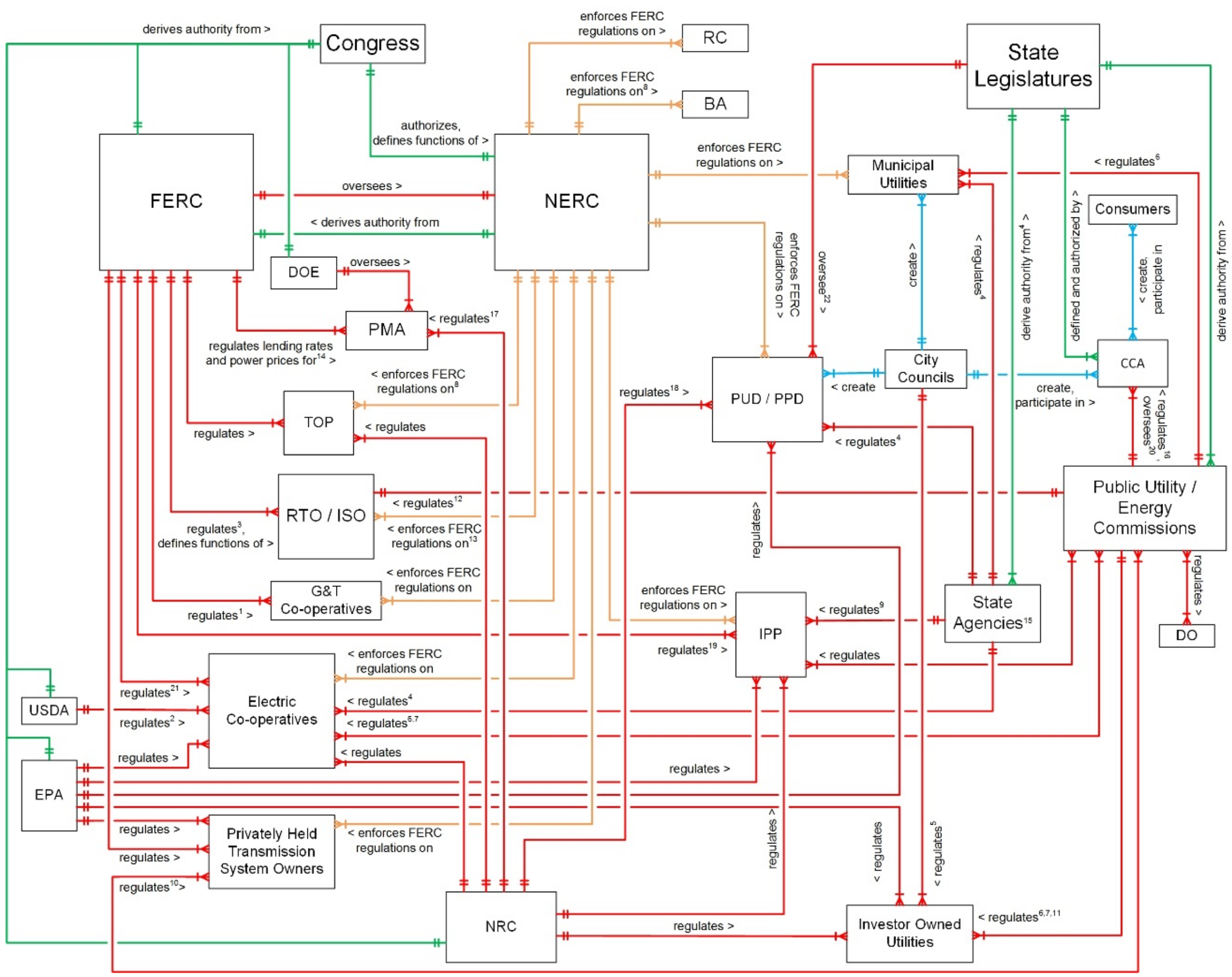

Figure 23: Regulatory Structure Model for U.S. Electric Sector

[1] "Quadrennial Energy Review: Second Installment", Washington D.C., Jan. 2017

4.4 Market Interaction

Wholesale markets have been created within the bulk power system to take advantage of competition and provide economically efficient generation and delivery of wholesale electricity as a commodity. A well-designed market plays an important role in ensuring economic operation and enhancing reliability. Markets can be structured or unstructured, and in both these types of markets the market participants may find themselves in long or short positions for short periods of time. These positions are traded on power exchanges which have been described in greater details in Section 3.2.20. Another element related to the markets are the transmission system reservation systems, for example OASIS which has been briefly discussed in Section 3.2.15.1.

4.4.1 Structured Markets

In the regions which have RTOs or ISOs, they administer the wholesale electricity markets which serve about two-thirds of the U.S. population. These are referred to as “structured markets.” The designs of these markets are however not the same, but unique based on the needs of the region. The Market Interaction functional group of the ERCOT region, which has a structured wholesale market, is shown in Figure 24.

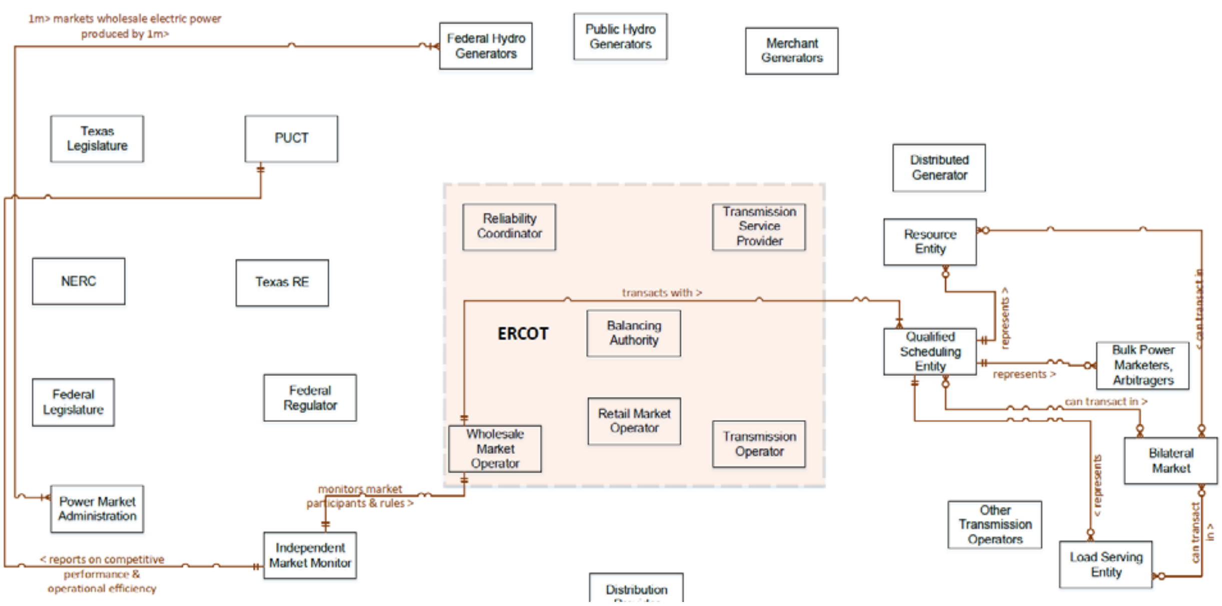

Figure 24: "Structured market" in the ERCOT region

In the structured market typically three types of energy products may be transacted – electrical energy, ancillary services and capacity. The descriptions of each are provided below.

4.4.1.1 Electric energy: Day-Ahead Market (DAM) and Real-Time Markets (RTM)

Electrical energy is the core product of the market, and the wholesale electricity price, known as locational marginal price (LMP), is determined through competitive bids. The RTOs and ISOs typically operate DAM and RTM. In the day-ahead market, suppliers (or generators) submit offers primarily based on the cost to generate electricity, and LSEs submit bids based on their load predictions, all for the next day. The load forecasts include weather or other pertinent information. Based on the bids and the offers, and the full transmission model, the RTO/ISO performs UC for each hour of the next day to find an optimal solution and therefore determines the hourly LMPs at defined locations within its area. This approach selects the lowest cost resource to supply the next increment of power to a given point of interface (in CAISO referred to as a P-Node) between the bulk power system and a distribution system. In order to accommodate the deviations from the day-ahead commitments and ensure reliable supply during the course of the operating day, there is also a RTM. The RTO/ISO receives updated offers from the suppliers and perform ED for determining actual dispatch of generation which will balance the system. The balancing of the system using LMPs determines the price of electricity for a given period of time, say every 15 minutes for the coming 24 hours. PJM calculates 5-minute LMPs based on the actual operating conditions and performs financial settlement on hourly integrated LMP. At present the wholesale market is not designed to coordinate generation from DER, and this is one of the gaps which becomes apparent when we study the industry structure diagram. With the increased deployment of DER in the regional grids, it is imperative that some attention be paid towards better integration of DER services in the market operations which is expected to result in improved overall coordination.

4.4.1.2 Ancillary Services

As part of the Ancillary services market, RTOs/ISOs typically procure ancillary services like regulation and reserves in order to handle fluctuations, which may occur due to mismatches between load and generation, or due to unforeseen events like loss of generation unit or transmission facility.

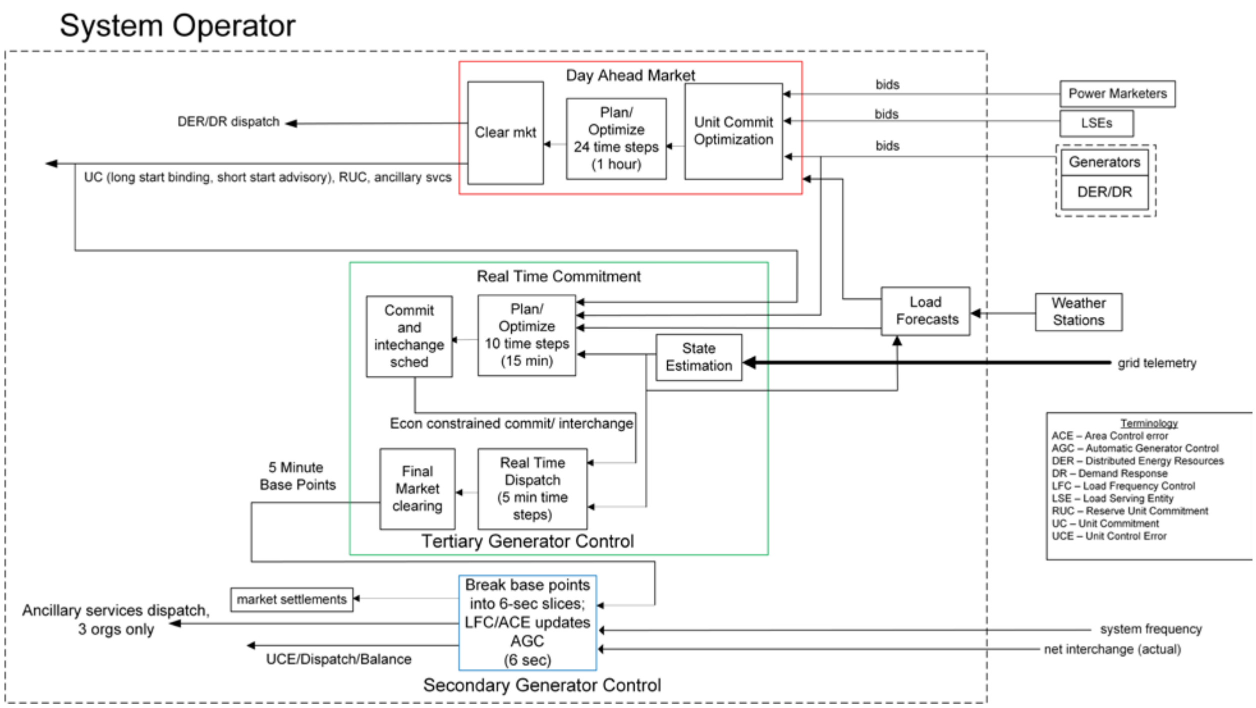

Figure 25: Market control diagram for NYISO

Figure 25 shows the market control diagram for NYISO. This is a sample example which shows the inputs which are received from the various entity classes, the various computations/processes that are performed to determine the commitment and dispatch decisions, and their time granularity. Market control diagrams for different RTOs may look very different from each other.

4.4.1.1 Power capacity

Some RTOs/ISOs operate capacity markets for ensuring that there are enough resources to meet the demand at all times. For example, PJM and ISO-NE procure capacity through a competitive auction annually three years before the operating period, while NYISO consists of three auctions to procure capacity over shorter time frames. ERCOT does not have a capacity market.

Something to note is that the market trading only accounts for somewhere around 5% to 10% of the power delivered. This is the power needed to balance the system. The power delivered is in some sense based on a stack of contracts.

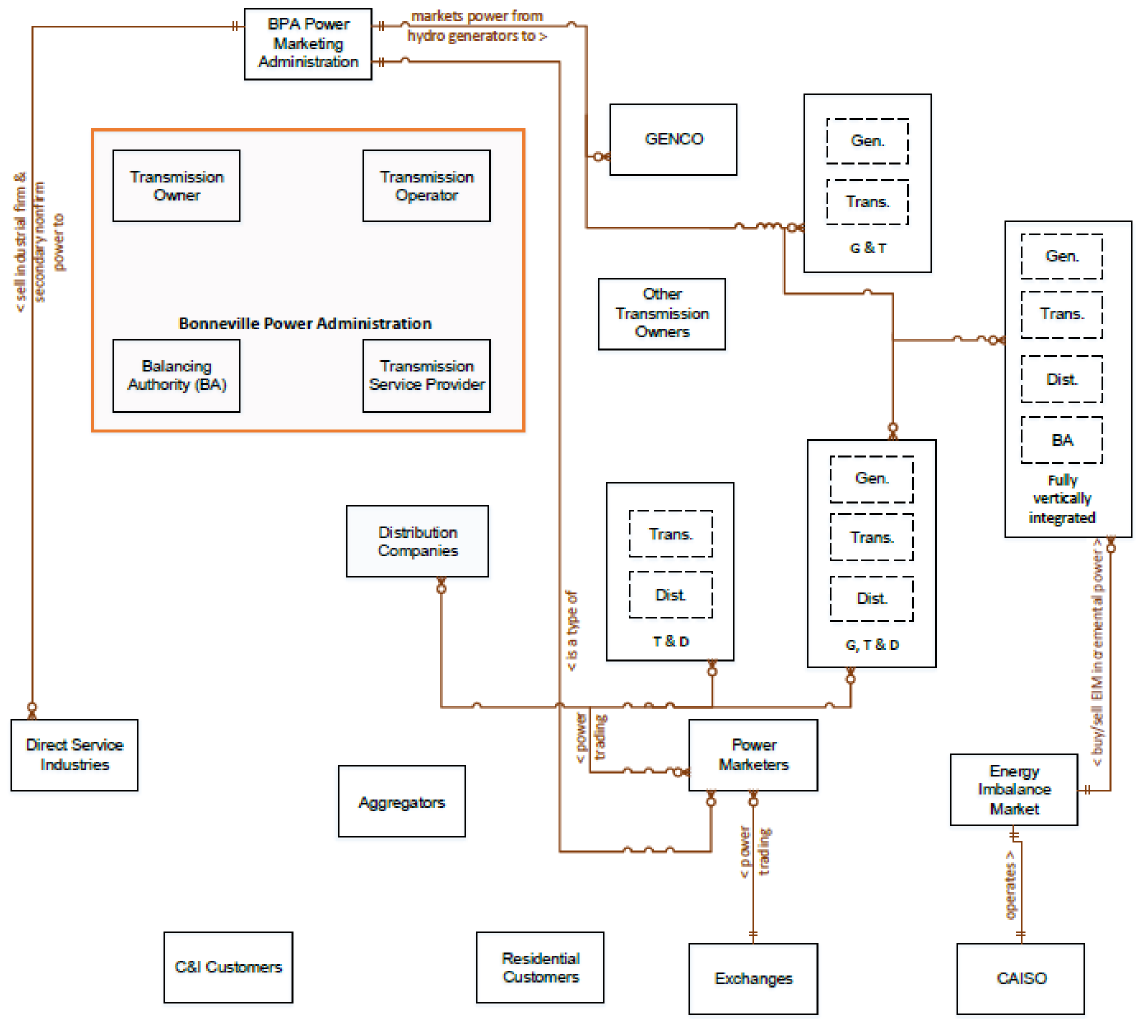

Figure 26: Unstructured market in the Pacific Northwest region

4.4.2 “Unstructured” Markets

The other parts of the U.S. do not operate structured markets, and these regions are sometimes referred to as having “unstructured” markets. In such regions, energy transactions are primarily based on long-term bilateral contracts between the electric energy suppliers like generators, and resellers like distribution utilities in which the two parties agree on a fixed price, time and location of delivery. The bilateral contracts generally impose financial consequences on parties in the event that they fail to fulfill their part of the agreed transaction, for example if a buyer fails to make payment, or a seller fails to deliver on time. Unstructured markets exist in the northwest, southwest and southeast parts of the U.S. The BAs are responsible for procuring power, dispatching energy and providing non-discriminatory access to the transmission system. The bilateral transactions can take place directly through negotiation, via a broker, or an electronic trading platform. The agreements can range from contract packages, which are standardized, to complex contracts, which are customized. One thing to note is that in these unstructured market regions, vertically integrated utilities which own their own generating plants, transmission system and distribution lines are responsible for the entire flow of electricity from production to end-use.

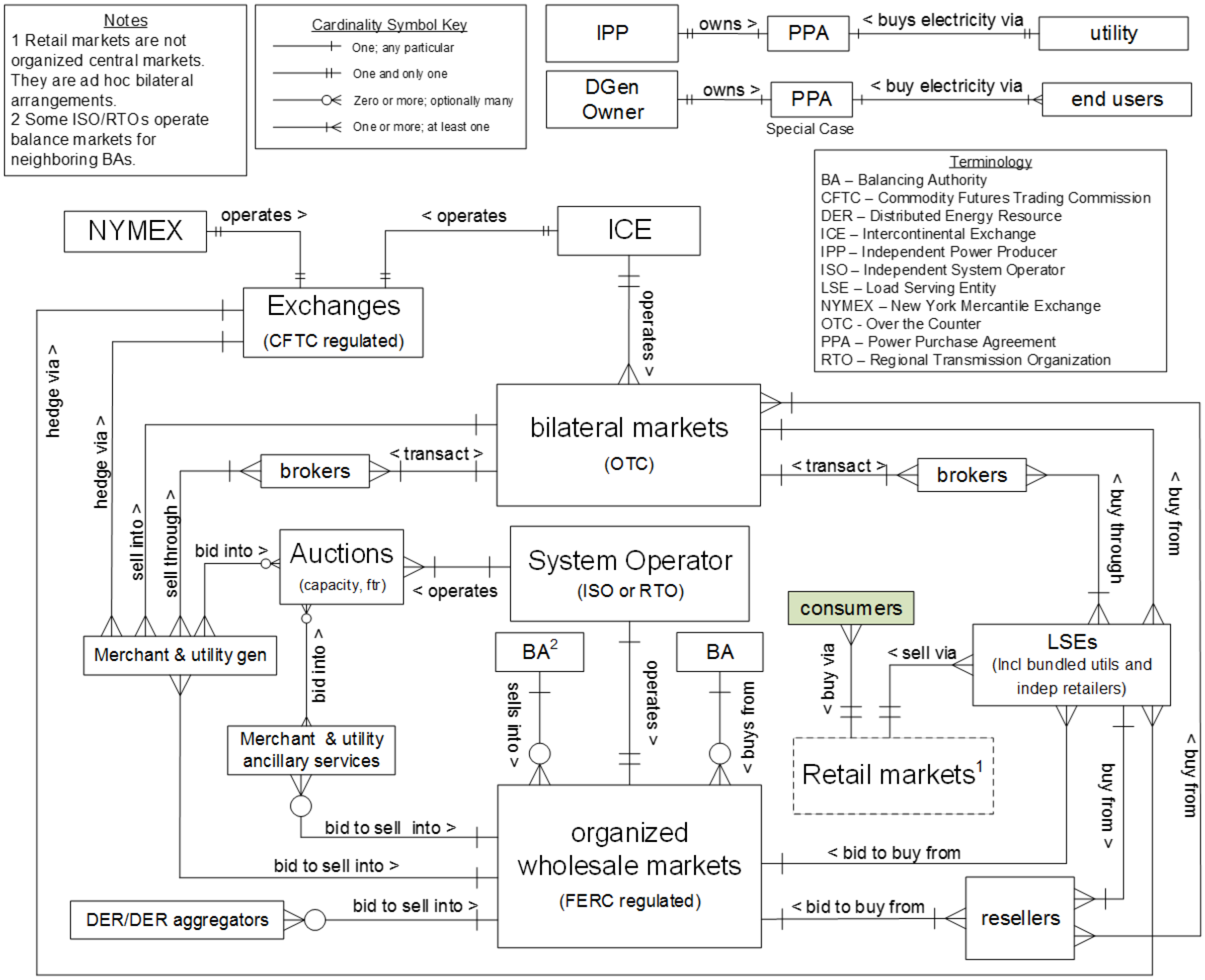

Figure 27: Typical entity classes and their relationships in the wholesale electricity market

Like in the structured markets, in unstructured market regions too similar steps are taken to consider the coming 24 hours, the simple difference being that they do not involve market-based bid and closing processes to determine the dispatch stack. The dispatch stack, also sometimes referred to as a portfolio, is generally calculated once for the coming 24 hours the afternoon before the 24-hour period starts.

In regions with both types of markets, there may be spot markets which involve multiple buyers and sellers who submit bids and offers, and market clearing results in market signals which include cleared quantities and prices. These indicate to the participants how to proceed, but do not involve direct relationships between individual buyers and sellers.[1]

4.5 Retail

"Retail" refers to the sales of electricity to end-use customers, where the customers may be residences, businesses or even industrial facilities. As shown in Figure 28, in the U.S. in eighteen states and Washington D.C. retail markets are competitive which means that consumers are able to choose between competitive retail suppliers[2]. This allows customers to choose their own electricity provider and generation options which includes renewable energy. Competitive retail suppliers provide a variety of service plans that give consumers and businesses options for electricity purchases. The price the end-user

[1] https://gridarchitecture.pnnl.gov/media/advanced/Market_Control_Structure_v0.2.pdf
[2] https://www.epa.gov/greenpower/us-electricity-grid-markets

pays, or the retail price, may not reflect the real-time pricing of wholesale market pricing, and additional factors need to be considered to determine the retail price. In Texas, 75% of all the electricity is sold to retail choice customers. Figure 29 shows the Retail functional group diagram for ERCOT.

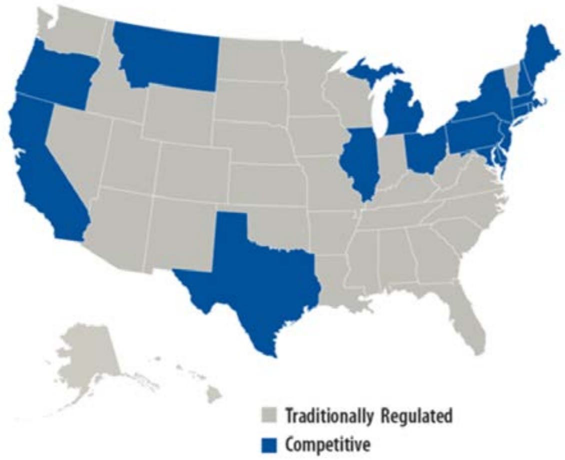

Figure 28: Types of retail markets in different states in the U.S.

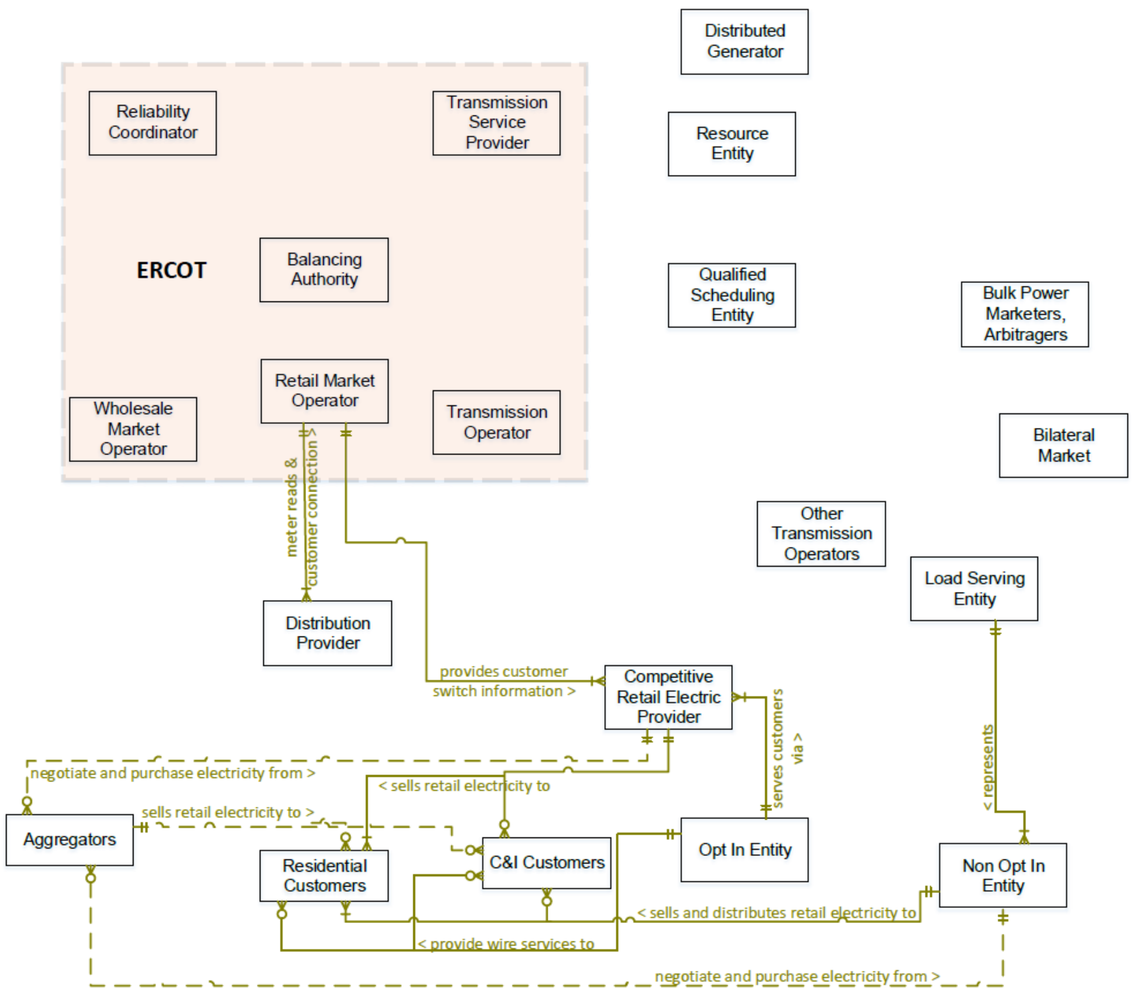

Figure 29: Retail functional group in Texas which offers customer choice

In the other states, the retail market is traditionally regulated. Customers in these areas do not have multiple retailers to choose from, and the local utility provides both wires services as well as sale of energy as a bundled product. Figure 30 shows the Retail functional group diagram for the Pacific Northwest region which does not have CRs.

The retail rates to be charged by municipally owned utilities and cooperatives are typically established by the governing board or city council. As discussed in Section 4.3 the retail rates for IOUs are typically determined at the state-level, and the regulatory body is generally concerned with allowing the utility to recover operating costs, make agreed to investments in system improvements, and to provide a return on investment to stakeholders. These rates usually contain several components, like energy charges, demand charges, customer surcharges, and sometimes environmental surcharges.[1] The resulting rates, also called tariffs, are then used to charge customers. Historically rates have been volumetric, that is to say based directly on the quantity of electricity sold to a customer. Cost recovery and return on investment, etc. all had to be covered by the allowed rate. More recently, rates have been structured to include fixed fees, for example for cost recovery. This move is being taken since with increased energy efficiency measures, distributed generation by prosumers, and for other reasons infrastructure costs of utilities are not well recovered with a volumetric approach.

Customers and aggregators transact at the regulated retail rate. There can be different rates, such as time-of-use, tiered rates and demand charges that change based on the amount of energy used, and in limited instances real-time varying rates. There have been experiments with retail markets, for example with transactive energy systems, but these have yet to be used persistently in the United States.

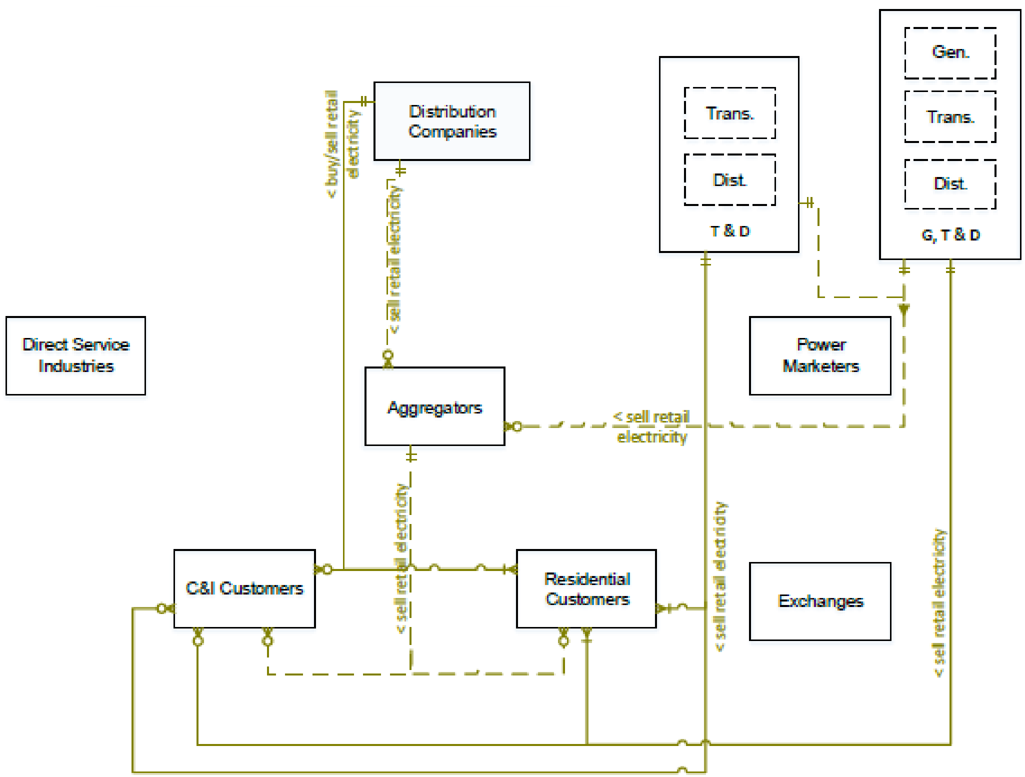

Figure 30: Retail functional group in the Pacific Northwest region

1 https://content.next.westlaw.com/Document/Ieb49d7b91cb511e38578f7ccc38dcbee/View/FullText.html?contextData=(sc.Default)&transitionType=Default&firstPage=true&bhcp=1

4.6 Reliability Coordination

Reliability coordination activities generally fall under the purview of NERC. NERC develops Reliability Standards using an industry-driven, ANSI-accredited process that aims to ensure the process is transparent to public, and open to all entities who are affected by the reliability of the North American bulk power system. NERC has developed a Reliability Functional Model (currently version 5) which defines and describes a number of functions which define a set of tasks that must be performed in order to ensure reliability of the bulk electric system. Each function is assigned to a functional entity which is responsible for the identified tasks. The Functional Model also describes the relationships between the various functional entities. It serves as the foundation for development and maintenance of reliability standards by NERC and establishes the requirements that organizations need to meet if they register to perform a certain reliability function. The Organization Registration and the Organization Certification Programs of NERC allow organizations like bulk power system owners, operators and users to register for certain reliability functions. NERC publishes lists of these organizations and the functions they have registered to perform.

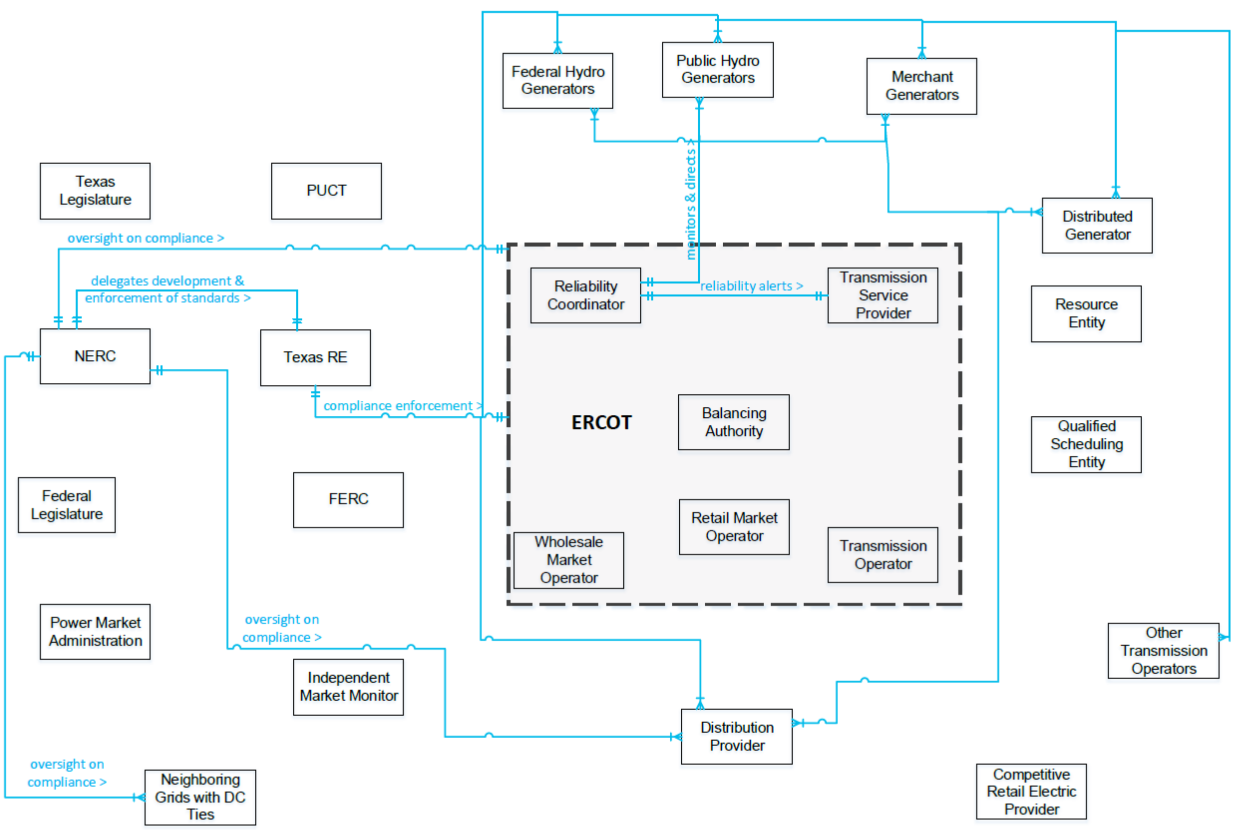

Figure 31: Reliability Coordination functional group for the ERCOT region

NERC delegates authority to perform compliance monitoring and enforcement to the seven RREs who are granted some degree of flexibility for accommodating the regional uniqueness. The RREs are responsible for assuring mitigation of any violations of the applicable reliability standards and assess sanctions or penalties when an organization fails to comply. NERC being the ERO oversees these regional programs in order to ensure consistency and fairness of the delegated functions.

Each RRE establishes one or more RCs who are tasked with maintaining real-time operating reliability and coordinating emergency operations within its service territory and in coordination with its neighboring RCs. RCs have certain decision-making authority to direct entity classes like TOP, BA, GOP, TSP, LSE, and PSE for preserving the integrity and reliability of the Bulk Electric System within their areas[1]. Figure 31 shows the Reliability Coordination functional group for the ERCOT region.

4.7 Energy and Ancillary Services

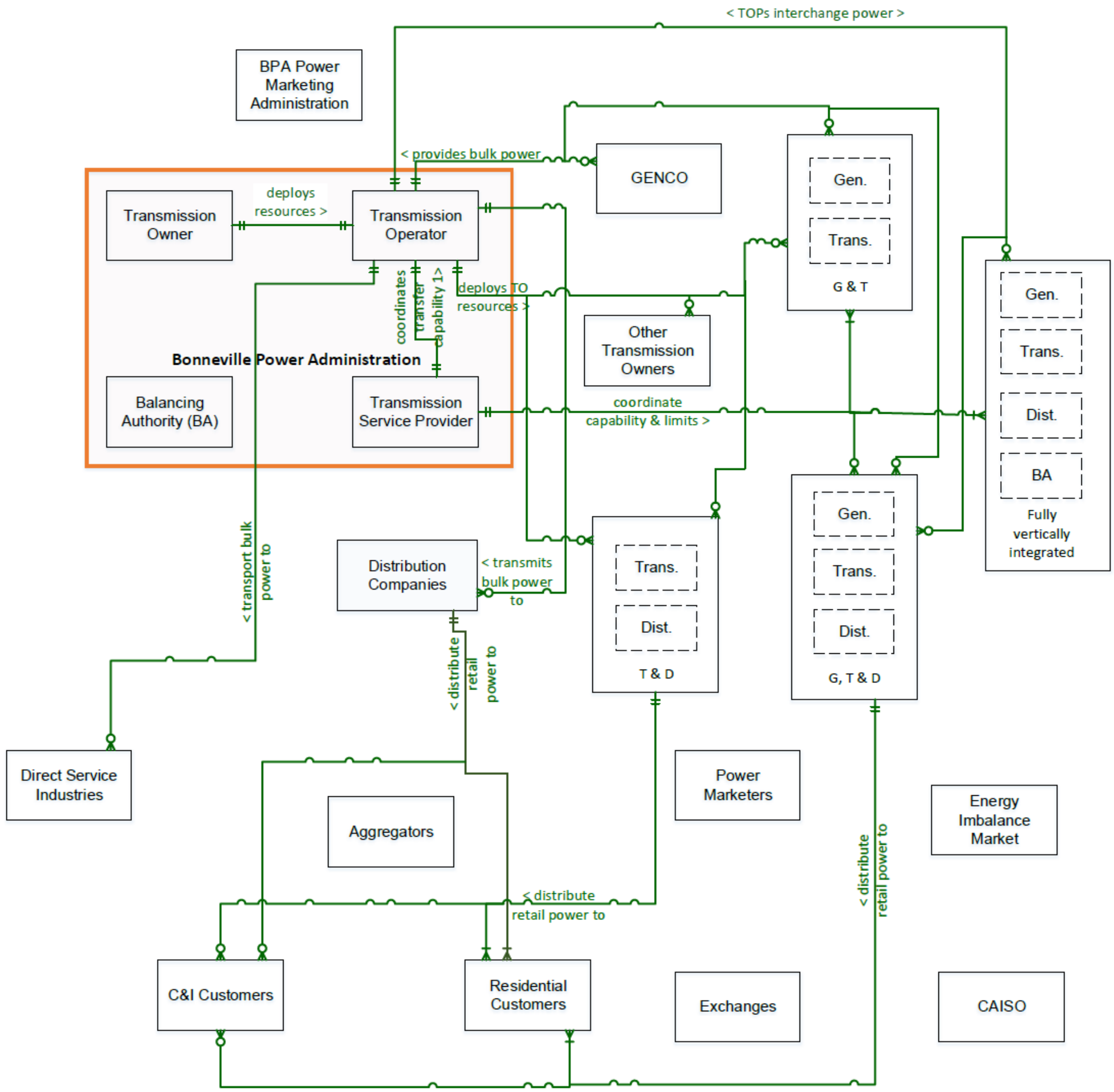

Figure 32: Energy and Ancillary Services functional group in the Pacific Northwest region

"Energy and ancillary services" encompass the provisioning and delivery of electric power from generators to customers, and the possible engagement of flexibility on the part of the customers to provide services to the electric power system. In this functional group, energy services include generation, transmission and distribution services. Generating facilities produce and transfer bulk electric energy to the connected transmission system. The TSP coordinates transfer capabilities and other reliability limits related to the transmission system and approves or denies transmission service requests from the GO,

[1] https://www.nerc.com/files/IRO-001-1_1.pdf

LSE and PSE. If the transmission service request is approved, the concerned TOP transmits the bulk electric power to the intended LSE or distribution utility. The distribution utility then physically delivers the electrical energy to the different types of customers connected to its system. Customers typically consist of residential, commercial and industrial end-users. In places where electric vehicles are proliferating even transportation customers should be considered as a separate entity class.

Ancillary services are necessary for balancing generation and load at every instant in spite of fluctuations in both, and thereby play a critical role in maintaining the stability and reliability of the grid. FERC has defined ancillary services as those "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system". Six typical ancillary services are provided by the resources in most regional power grids, irrespective of the market design as listed in Table 7. Note that loads may also provide ancillary services by participating in demand response programs. Figure 32 shoes the Energy and Ancillary Services functional group for the Pacific Northwest region.

Table 7: Types of ancillary services[1]

Condition	Ancillary Service	Purpose	Response Speed	Duration
Normal	Continuous Regulation	For correcting min-to-min fluctuations	~1 min	Min
	Energy Imbalance Management	Bridge between real-time energy schedules and regulation service	~10 min	10 min to hours
Contingency (Disturbance)	Instantaneous Contingency Reserves	For rapidly increasing or decreasing generation/consumption in response to a major disturbance	Seconds (< 10 min)	10 to 120 min
	Replacement Reserves	For replacing or supplementing Instantaneous Contingency Reserve	< 30 min	2 hours
Other Services	Voltage Control	For maintaining transmission system voltages	Seconds	Seconds
	Black Start	Generation able to start without support from the grid	Minutes	Hours

4.8 Control and Coordination

One of the critical functional groups which ensures stable and sustained operation of the integrated system in a seamless manner is the Control and Coordination functional group. Some of the key processes involved are sensing, data acquisition, data analysis and actuation.

Control of the grid involves a number of elements:

- Unit Commitment
- Dispatch & Curtailment
- Load Sharing
- Flow Control
- Balance

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1 https://www.energy.gov/sites/prod/files/oeprod/DocumentsandMedia/Loads_providing_Ancillary_Services_main_report_62701.pdf

- Interchange
- Frequency Regulation
- Voltage Regulation
- Reactive Power Regulation
- Stabilization
- Synchronization
- Demand Response
- Storage energy flow and State of Charge control

Electricity markets may be viewed as a means to implement a form of distributed control.[1]

Coordination is the means by which a set of decentralized elements to cooperate to solve a common problem, thus becoming a distributed system. Grid coordination is the systematic operational alignment of utility and non-utility assets to provide electricity delivery. For the grid this involves multiple structure classes, including industry structure.[2]

4.8.1 Sensing and Data Acquisition

Grid operators largely rely on SCADA data for monitoring the state of the system, detecting any abnormal conditions and controlling equipment in the substations.

At the transmission level, most sensing is done in the substations although there are some sensors for use out on the actual transmission lines and towers (line sag and wind-induced sway, ice loading, and some specialized current flow sensors). The bulk of the sensing is done in the substation with voltage and current transducers. Where digital relays are used, these devices can produce a wide array of raw measurements and computed values. Substation equipment health is also monitored through a variety of specialized sensors. A station RTU or gateway provides a data aggregation point and communication interface back to the control center. Synchronized wide area measurements are accomplished via Phasor Measurement Units (PMUs) also located in transmission substations.

Growing numbers of PMUs have been deployed in North America. There has been a corresponding increase in effort towards developing algorithms for predicting system state and assessing system stability to increase situational awareness and avoid transmission system blackouts.

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[1] JD Taft, Electric Grid Market-Control Structure, PNNL-26753, June 2017, available online: https://gridarchitecture.pnnl.gov/media/advanced/Market_Control_Structure_v0.2.pdf

[2] JD Taft, Architectural Basis for Highly Distributed Transactive Power Grids: Frameworks, Networks, and Grid Codes, PNNL-25480, June 2016, available online:
https://gridarchitecture.pnnl.gov/media/advanced/Market_Control_Structure_v0.2.pdf
https://gridarchitecture.pnnl.gov/media/advanced/Architectural%20Basis%20for%20Highly%20Distributed%20Transactive%20Power%20Grids_final.pdf

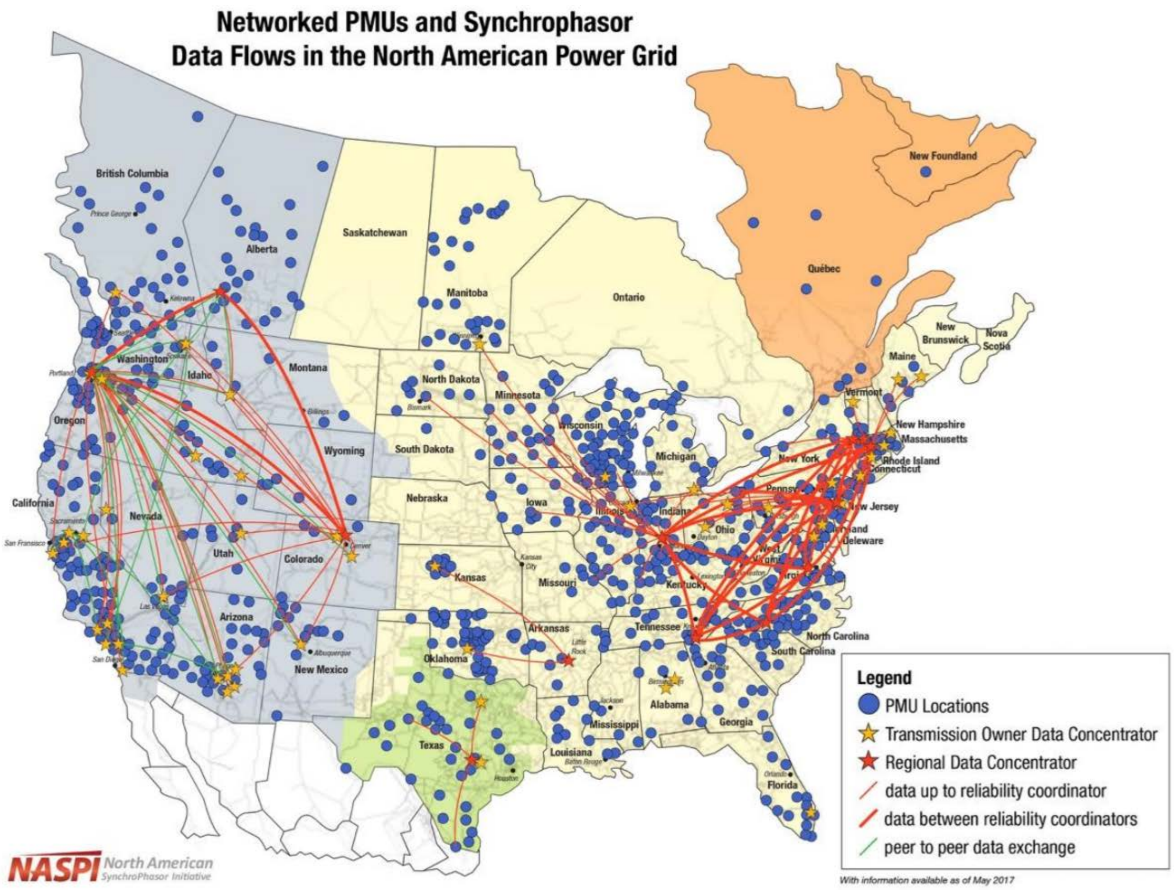

Figure 33: Location and data flows from PMUs in North America[1]

Standard transmission level telemetry operates on cycles times tine the 2-6 second range, However, PMUs generate precisely time-stamped voltage and current phasor measurements, and frequency measurement at high frequency (typically 30 or 60 readings per second). By 2017 over 2500 networked PMUs had been deployed in North America. GPS-based timestamping enables the grid-wide measurements to be time-aligned based on a common time reference. These high volumes of highly granular and synchronized data allow operators to obtain a more accurate view of the system, and help in wide-area monitoring, control and protection.

At the distribution level, instrumentation tends to be sparser but sensing at the substation level is similar to transmission. Distribution SCADA (for sensing devices outside the substations on the distribution feeders) may or may not exist, but when it does, it is usually implemented as a combination of a set of line transducers and an RTU with embedded processing capability, as well as one or more communication interfaces.[2] Control devices such as reclosers may have internal sensing that can transmit data via communications links back to control centers as well.

Sample rates tend to run lower at the distribution level (one to several minutes per cycle) but rates are being driven to be faster due to increasing dynamics of distribution operations. While there has been discussion of applying PMU technology at the distribution level, not much has actually been implemented. Distribution systems have much smaller angle differences which change too frequently to

[1] https://www.energy.gov/sites/prod/files/2017/09/f36/2_Modern%20Grid-networked%20Measurement%20and%20Monitoring%20Panel%20-%20Alison%20Silverstein%2C%20NASPI.pdf
[2] https://gridarchitecture.pnnl.gov/media/advanced/Sensing_for_Advanced_Grids_v1_7_GMLC.pdf

resolve using data from ordinary PMUs. Research on the development of micro-PMUs to provide accurate, extremely precise synchronized voltage and current phasor measurements is ongoing.

At either level, Digital Fault Recorders record sampled waveforms of signals (like voltage and current signals), the status of relays and other physical quantities. DFRs are able to detect disturbances and record pre-fault, fault and post-fault data which can be used for postmortem analysis of the disturbance.

Advance Metering Infrastructure (AMI) is an integrated system of smart meters, communications networks, and data management systems that enables two-way communication between distribution utilities and premises metering[1]. Traditional electric meters allowed basic functions like meter reading, disconnection and reconnection of electric service, formerly performed manually by personnel, to be automated and remote.

4.8.2 Data Analysis

At the transmission level, a number of analyses are run on a continuing basis, principle among them being State Estimation. This process uses SCADA measurements (bus voltage magnitude, real power injections, reactive power injections, active power flow, reactive power flow) and in the context of the system model to eliminate bad data and produce reliable estimates of the system states (voltages, currents, phase angles, power flows). Using the state estimates it is possible to determine whether the system is operating in normal, emergency or restorative state, and take any corrective or preventive actions, if needed.

Contingency analysis is another important application which simulates contingency scenarios and evaluates the impacts. A contingency is defined as "the failure or loss of an element (e.g. generator, transformer, transmission line, etc.), or a change of state of a device (e.g. the unplanned opening of a circuit breaker in a transformer substation) in the power system"[2]. If the number of components in a system is assumed to be N, then according to the N-1 security criterion the power system must remain secure in the event that any single component of the system fails and continue to operate with N-1 components.

Distribution systems have not typically had state estimation tools, due to lack of sufficient measurements and lack of good systems models. Consequently, they generally have a form of partial state determination (based on partial direct visibility), as opposed to full state estimation. Line sensor readings, faulted circuit indicator states, meter data, and data from substations and some line devices such as reclosers are used by the operators to understand the state of the distribution system.

Figure 34 illustrates an emerging view of modern electric distribution, with substation sensing, line sensing, various DER and grid control devices.

[1] https://www.smartgrid.gov/recovery_act/deployment_status/sdgp_ami_systems.html
[2] http://smartgrid.epri.com/UseCases/ContingencyAnalysis-Baseline.pdf

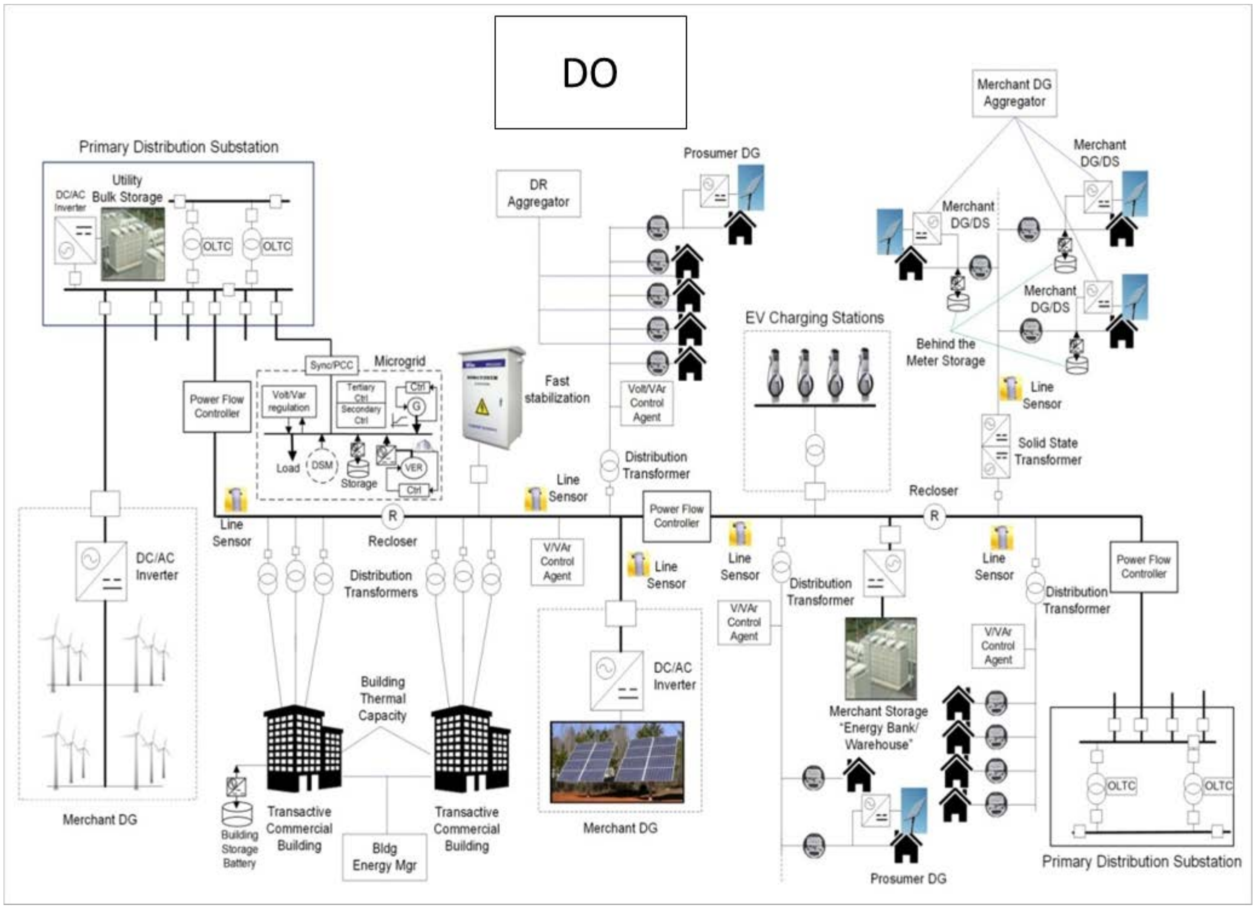

Figure 34: Distribution system reference model example schematic

4.8.3 Actuation

At the transmission level, protection and control devices are located in the substations. These include

- Circuit breakers
- Switches
- Voltage regulators
- Capacitor banks
- Variable frequency transformers
- Phase shifting transformers
- Synchronous condensers
- Power electronics devices

In the area of power electronics, FACTS (Flexible AC Transmission Systems) are a family of subsystems that are attached at the transmission level to provide control of voltage and real and reactive power flow. As such they can be used to stabilize transmission systems, which are complex dynamic systems. FACTS use power semiconductors along with reactors (inductors and capacitors) to provide continuous compensation for voltage, current, real power, reactive power, or combinations thereof. FACTS operate as closed loop control systems that run continuously). Some FACTS get their feedback signals from the grid locally; others make use of signals from remote locations, including from remote PMU's. An example of a remote sensing application is modal power oscillation damping, in which signal from two widely separated PMUs are combined to make an error signal that drives the FACTS to dampen the power oscillation.

FACTS sub-systems reside in transmission substations normally, although in some cases they can be installed as standalones or at the point of common coupling of a wind or solar farm or at some load that is a cause of instability that requires regulation or compensation.

There have been, roughly speaking, two generations of FACTS technology. Each makes use of power semiconductors to provide rapid switching of reactive elements (capacitors and inductors) in a manner that affects transmission line voltage and power flow.

The first generation included static VAR compensators, thyristor-controlled series capacitors and thyristor-controlled phase shifters. SVC's achieved a fair amount of penetration into the industry; the others less so. The second generation includes STATCOM (static series compensator), static synchronous series compensators, the unified power flow controllers, and the interline power flow controllers. The performance characteristics of the two generations are different of course, but they both make use of power semiconductors for fast operation. Earlier designs could affect reactive power only, whereas newer approaches provide real and reactive power control as well as voltage regulation. The details become increasingly complex from there.

Some FACTS devices are shunt connected (connected from transmission line to ground) whereas others are series connected (connected in-line in a transmission line).

More recently, single-phase, modular static synchronous series compensators have been applied to transmission line flow control for congestion management.

Finally, inverters are used to convert the DC power from wind and solar arrays to AC for the grid and the interconnection interties use AC-DC-AC converters to transfer power between major interconnections.

At the distribution level, protection and control devices are located in the substations and on the feeder circuits outside of the substations.[1] These include

- Circuit breakers
    - relay-controlled, in substations
    - at microgrid PoCs, controlled by synchronizing relays
- Switches, manual, automatic, or remote-controlled
    - Fault interrupting
    - Load interrupting
    - Sectionalizing
- Reclosers
- Voltage regulators
- On Load Tap Changers in substations
- Serial line drop compensators
- Capacitor banks
- Line fuses

Power electronics is mostly confined to inverters for interface of rooftop solar arrays and some storage devices to the grid. There is also a power electronics device made for attachment to feeder secondaries to regulate voltage in the presence of fluctuations caused by rooftop solar inverters. It is not in wide use as of 10/2020. While there is research around "solid state transformers" and other approaches to embedding power electronics in distribution circuits, this is not common practice.

[1] JD Taft, P De Martini, and L Kristov, A Reference Model for Distribution Grid Control in the 21st Century, PNNL-24463, July 2015, available online: https://gridarchitecture.pnnl.gov/media/advanced/Distribution%20Control%20Ref%20Model_v1.1_final.pdf

A secondary level of control for distribution grids is apparent load management. This is accomplished via Demand Response and by the use of storage and distributed generation to offset load. In some cases, this is done behind the meter in a manner transparent to the grid operator. In other cases, the distributed generation and DR are made dispatchable by either a grid operator or a third-party operator such as an aggregator or remote building energy manager.

Figure 35 illustrates a forward-looking data-flow centric reference model for distribution-level control. Note that the DSO function does not yet exist in the U.S. except in a few experimental trials.

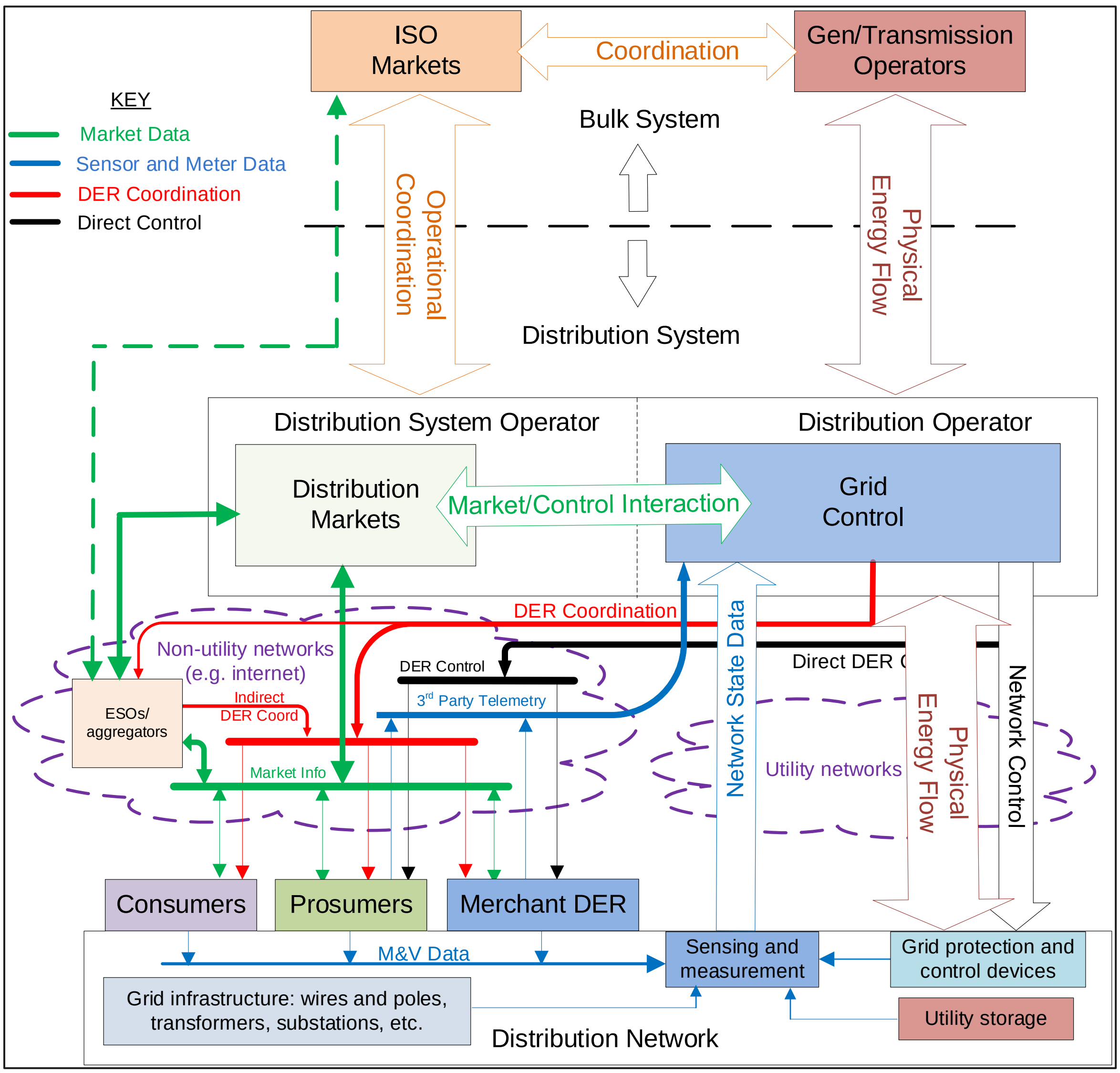

Figure 35 Distribution Control Reference Model

5.0 Reference Architecture Specific Considerations

This Problem Domain Reference model provides background for each of the five reference architectures being developed by the GMLC Grid Architecture project. Each subsection summarizes considerations related to the topic of the associated reference architecture. The subsection concludes with a set of high-level objectives addressed by the associated reference architecture.

5.1 Advanced Bulk Power Systems (Track 1)

5.1.1 Business / Operations Context

The bulk power system includes those elements of the electric power system that generate large quantities of electricity that is moved through the electric power transmission system for delivery to end uses via electric power distribution systems. Critical interactions, for example with natural gas systems providing fuel to gas turbine generators, are included. The business and operations of the bulk power system have evolved in recent years with the introduction of large scale variable renewable energy such as wind generation and large scale solar, concerns about system resilience (see the High Resilience Reference Architecture), and changing economics related to both the low or zero fuel costs associated with renewable energy resources in both the bulk energy system and in distributed energy resources enabling self-supply in distribution systems. One impact in particular, is that of utility scale storage in the bulk power system or the distribution system. Storage at this scale introduces buffering into the system with operational and economic impacts.

These changes impact both the operation of bulk energy systems, the business models of bulk power systems, and their interaction with distribution systems. Historically the market and other economic models used in bulk power systems have followed a deterministic power dispatch model (a load following model) assuming a one-way flow of power and no self-supply in distribution systems. The variability of renewable energy resources, emergence of self-supply in distribution systems, and the need to coordinate between bulk energy systems and distribution systems call for new economic and market models that can accommodate these interactions. The new economic and operations paradigm is often referred to as a supply following model. These changes will affect both the business of bulk power systems and their operation.

5.1.2 Regulatory / Policy Context

Bulk energy systems in the United States that have interstate networks are subject to regulation by the Federal Energy Regulatory Commission. This regulation is primarily focused on their market mechanisms and economic activity. Operations of bulk power systems in North America are subject to oversight by the North American Electric Reliability Corporation (NERC).

The oversight by FERC and NERC is based on the load following approach that has been in place for years. As new operations and economics are introduced supporting a change to supply following model the regulations (FERC) and requirements (NERC) must be updated.

5.1.3 Objectives

As described in the reference document **Grid Architecture 2** (see Section 2.6), modernized grids must support seven system Qualities namely Delivery, Conservation, Preservation, Protection, Adaptivity, Enablement, and Merit. Collectively, these Qualities encompass the issues of supply, reliability, renewables integration, conservation, safety, cyber-security, and affordability, as well as many others. In order to support these Qualities, a number of advanced bulk energy system objectives must be met when the system is under stress. They are:

- Articulate structures for integration utility scale storage
- Define market structures responding to increased variability and transition to a supply following system
- Identify control and coordination structures facilitating operation of utility scale storage
- Consider opportunities for incorporation of advanced power electronics as they related to constraint / congestion management

5.2 High Resilience Grid (Track 2)

5.2.1 Business / Operations Context

The electric power system has gone through significant change over the past 15 years. Early in this period the change was largely the introduction of so called “smart grid” technology, basically a growing use of information and communications technology (ICT). This growth in ICT infrastructure, however, resulted in increasingly complex system control and coordination, and expanded the cyber security vulnerability space. Both considerations expand the set of risks that must be considered from a resilience perspective.

The structure of the system has largely been one of one-way power flow from generation assets in the bulk power system delivering power through a meshed network of transmission lines to distribution substations which then delivered power through a set of distribution feeders typically having a radial structure. The exception to this latter structure was some urban environments with meshed or “copper plate” structures usually in their downtown service areas. With this set of structures, concerns about system resilience were focused on the bulk power system as the source of supply.

During this period there has been steady growth in renewable electricity generation, primarily wind energy, on the bulk power side and in solar energy within distribution systems at both utility scale and through residential installations. These changes motivate a change in the way resilience is considered. For example, the growth of renewable energy resources within the bulk power system and distribution systems changes the percentage of power coming from resources with physical inertia. Other recent developments include the trend toward local energy choice, leading to such structures as microgrids, community solar and wind, and Community Choice Aggregators, which are utility legal entities in several states. Some large Investor Owned Utilities have declared that they will convert their distribution systems from one-way energy delivery channels to broad access networks, where any qualified party may carry out electric energy transactions. Such changes in utility business models have significant implications for grid control and resilience. In particular, the growing level of self-supply in many distribution systems expands the consideration of resilience from just the bulk power system to the entire electric power system. This, in turn, requires new ways of thinking about and addressing resilience as discussed in **Theory of Grid** Resilience, a white paper prepared in support of this work. Additional changes are evident in the **GMLC 1.2.1 Emerging Trends.xlsx** spreadsheet, chief among them are the rise of prosumers and third party DER services organizations.

5.2.2 Regulatory / Public Policy Context

Resilience has historically been considered a problem associated with the bulk power system (as the only source of supply historically) and has thus been addressed by federal regulation through the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Council (NERC). Resilience has also been considered a special case of reliability associated with outages caused by extreme events such as natural disasters, with utilities being excused from reporting reliability metrics to regulators in such circumstances. In recent years utilities responsible for distribution systems have begun to consider how to re-engineer distribution systems to be more locally resilient to natural disasters through distribution level supply and application of structures such as microgrids. The U.S. Military has also undertaken measures to increase electric power resilience at many facilities through similar measures. The consideration of resilience within distribution systems will impact the regulatory considerations bringing state regulators into the discussion.

5.2.3 Objectives

As described in the reference document **Grid Architecture 2** (see Section 2.6), modernized grids must support seven system Qualities namely Delivery, Conservation, Preservation, Protection, Adaptivity, Enablement, and Merit. Collectively, these Qualities encompass the issues of supply, reliability, renewables integration, conservation, safety, cyber-security, and affordability, as well as many others. In order to support these Qualities, a number of resilience objectives must be met when the system is under stress. They are:

- Graceful degradation
- Accommodation of subsystem failure
- Recognition and mitigation of vulnerabilities
- Adaptability, flexibility and agility

5.3 High DER/High Automation, and High Storage Distribution Grid (Track 3)

5.3.1 Business / Operations Context

With growing DER deployment there comes a point where distribution system operations and the business of distribution utilities fundamentally change. New approaches are required to accommodate high penetrations of DER, in particular of rooftop photovoltaics. High penetrations of storage, in particular electricity storage, create operational and business opportunity through the introduction of buffering. Buffering affects the economics of electricity as a commodity and provides the operational opportunity, for example, for managed load shapes within a distribution system. Finally, large scale deployment of distribution automation allows for increasingly sophisticated distribution system control techniques including distributed control and optimization. One can expect that with increasing distribution automation that there will be a shift to more autonomous operation within distribution systems and a corresponding shift in operator responsibilities to situational awareness. There is also an impact on system maintenance and operation with a shift from manual, paper-based processes related to lineman safety and similar activity. This affects the day-to-day activities and activities such as service restoration following major outages.

On the business side, the growth in DER penetration and deployments of large-scale storage by utilities, customers, or third parties moves the electric power system more completely into a supply following model with customer choice of energy supply and opportunities for local energy supply arrangements.

Utilities are reconsidering their business models and exploring service-oriented models that put them in the role of coordinator or enabler of customer choice rather than provider of the electricity commodity.

5.3.2 Regulatory / Policy Context

High DER penetration levels affect regulatory and policy concerns relative to utility cost recovery and acceptable models for control and coordination of customer or third-party owned assets. For storage, there are regulatory and policy considerations related to utility ownership of storage assets and potential use of those assets for economic benefit through arbitrage or other economically motivated action (as compared to customer service.). The changes that utilities propose to their business models will also be a part of the regulatory and policy discussion. New business models that are outside of the traditional regulated monopoly will also affect the regulatory and policy dimension, for example, the community choice agreement (CCA) model that has become popular in California.

5.3.3 Objectives

As described in the reference document **Grid Architecture 2** (see Section 2.6), modernized grids must support seven system Qualities namely Delivery, Conservation, Preservation, Protection, Adaptivity, Enablement, and Merit. Collectively, these Qualities encompass the issues of supply, reliability, renewables integration, conservation, safety, cyber-security, and affordability, as well as many others. In order to support these Qualities, several high DER / high automation and storage objectives must be met supporting operation of an increasingly complex electric power system. They are:

- Reduced cost of integration and operation of high levels of DER attached to distribution feeders
- Operational flexibility
- Adaptability, flexibility and agility

5.4 Variable Structure Grid (Track 4)

5.4.1 Business / Operations Context

Growth in deployment of distributed energy resources by utilities, third parties, and customers increases system complexity. Growth in formation of microgrids and microgrid networks also increases the complexity. Of particular concern is management and control of more complex power flows while maintaining a reliable and resilient system, especially in distribution networks. There have been recent ARPA-E and other projects on routable power-flow using advanced power electronic devices. Use of these power electronic devices and conventional electro-mechanical switches allows for consideration of a combination of physical circuit topology changes (via electro-mechanical means) and what can be considered as logical (or virtual) topology changes (via power electronics.) These new operational possibilities increase operational complexity and support evolution of utility business models as they relate to accommodating customer choice of energy supply, battery and other storage systems, all while maintaining system reliability.

5.4.2 Regulatory / Policy Context

The deployment of new technologies and the expense of circuit modification for more meshed network topologies will require cost – benefit justification to regulators and other oversight bodies.

5.4.3 Objectives

As described in the reference document **Grid Architecture 2** (see Section 2.6), modernized grids must support seven system Qualities namely Delivery, Conservation, Preservation, Protection, Adaptivity, Enablement, and Merit. Collectively, these Qualities encompass the issues of supply, reliability, renewables integration, conservation, safety, cyber-security, and affordability, as well as many others. In order to support these Qualities, a number of variable structure objectives must be met supporting operation of an increasingly complex electric power system. They are:

- Operational flexibility
- Reduced integration costs
- Adaptability, flexibility and agility

5.5 Urban Converged Networks (Track 5)

5.5.1 Business / Operations Context

Urban converged networks represent the interconnections and interdependencies between various infrastructures associated with modern society. They include, for example, water networks, natural gas distribution networks, transportation networks, and so forth. Urban converged networks are the focus for this track because there is generally a high level of interconnection of infrastructure networks in an urban setting. It should be noted, that there are also interconnections and interdependencies outside of urban settings.

Operationally, each infrastructure network is focused on achieving its particular objective. Optimization of operations is done in the context of the specific network and its objectives – economic, temporal, capacity, or other characteristics that can be optimized. There is little, if any, co-optimization across multiple infrastructure networks. This is due to differences in ownership and in different beneficiaries of the service associated with each network.

Except for publicly owned infrastructure, municipal or other political jurisdiction, infrastructure networks are operated as separate business entities.

5.5.2 Regulatory / Policy Context

Many of the infrastructure networks are subject to regulation and to public policy considerations due to the broad impact of their operation on society and the dependencies of the general population, government and business on their services. They are generally subject to regulatory oversight in a manner similar to the oversight of the electric power system. In many cases the oversight is by the same regulatory body though this varies by regulatory jurisdiction.

5.5.3 Objectives

Section 2.2 of the reference document **Grid Architecture 2** discusses network convergence in general. The Urban Converged Networks reference architecture considers them in more detail, but for a limited set of converged networks. The objective of this reference architecture is to illustrate the architectural considerations for considering interdependencies and interactions between critical infrastructure networks for purposes of:

- Infrastructure resilience
- Economic or other co-optimization
- Analysis of impact of regulatory or policy action
- Modernization associated with digitization and distributed control of associated systems and devices
- Integration approaches for effective joint coordination, optimization, and resource sharing

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Jeremy Twitchell	PNNL

Glossary

Aggregator: A buying group that signs up customers to bargain on their behalf for electricity and related services[1].

Ancillary Services: It is a type of service in the wholesale market essential for ensuring continuous balance of electricity supply and demand on a minute-by-minute basis.

Balancing Authority (BA): Entity responsible for integrating resource plans ahead of time, maintaining load-interchange-generation balance, and supporting Interconnection frequency in real time in its area[2].

Balancing Authority Area (BAA): Within reliability regions, grids are broken down into balancing authority areas which were formerly known as a Control Area

Bilateral Agreement: A written statement signed by two parties that specifies the terms for exchanging energy[3].

Bulk Energy System (BES): The electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition[4]

Bulk Power System (BPS): "Bulk-power system" means- (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy[5].

Bundled Utility Service: A means of operation whereby energy, transmission, and distribution services, as well as ancillary and retail services, are provided by one entity [EIA Glossary].

Contingency: The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element [NERC Glossary].

Day Ahead Schedule: A schedule prepared by a scheduling coordinator or ISO before the beginning of a trading day to indicate the levels of generation and demand scheduled for each settlement period that trading day [EIA Glossary].

Demand Bids: A bid into the power exchange indicating a quantity of energy or an ancillary service that an eligible customer is willing to purchase and, if relevant, the maximum price that the customer is willing to pay [EIA Glossary].

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[1] http://www.aect.net/documents/2017/AECT%20Glossary%202017.pdf
[2] https://www.nerc.com/files/glossary_of_terms.pdf
[3] https://www.eia.gov/tools/glossary/index.php?id=electricity
[4] https://www.nerc.com/files/Final_BES_vs%20_BPS_Memo_20120410.pdf
[5] Mandatory Reliability Standards for the Bulk-Power System, Order No. 693, FERC Stats. & Regs. ¶ 31,242 (2007), order on reh'g Order No. 693-A, 120 FERC ¶ 61,053 (2007)("Order No. 693") at PP 76

Demand Response (DR): Demand response programs are incentive-based programs that encourage electric power customers to temporarily reduce their demand for power at certain times in exchange for a reduction in their electricity bills [EIA Glossary].

Distribution Automation (DA): Any automation which is used in the planning, engineering, construction, operation, and maintenance of the distribution power system, including interactions with the transmission system, interconnected distributed energy resources (DER), and automated interfaces with end-users.

Distributed Energy Resources (DER): Any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System (BES)[1]

Distributed Generator (DG): Generation assets that are connected at the distribution level

Distribution Provider (DP): Provides and operates the "wires" between the transmission system and the end-use customer.

Distributed Storage (DS): Storage assets that are connected at the distribution level

Distribution System Operator (DSO): Entity responsible for balancing supply and demand variations at the distribution level and linking the wholesale and retail market agents, while maintaining the traditional role of the operator as a custodian for distribution system reliability[2]

Economic Dispatch: The allocation of demand to individual generating units on line to effect the most economical production of electricity [NERC Glossary].

Electric Cooperative (Co-op): Co-ops are electric businesses owned by the customers they serve, with a governing board that regulates service [AECT Glossary].

Electric Utilities: Corporation, agency, authority, or other legal entity aligned with distribution facilities for delivery of electric energy to end users.

Federal Energy Regulatory Commission (FERC): Federal agency charged with regulating interstate energy transmissions and wholesale sales.

Field Area Network (FAN): Communication networks connecting devices spread throughout the distribution system.

Frequency Regulation: Variable amount of generation under AGC control dispatched by BA for maintaining system frequency at 60 Hz, and is obtainable within five minutes.[3]

Generator Operator (GOP): Entity that operates one or more generating facilities and performs the functions of supplying energy and Interconnected Operations Services [NERC Glossary].

Independent Power Producer (IPP): Entity that owns or operates facilities for the generation of electricity for use primarily by the public, and that is not an electric utility.

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[1] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf
[2] https://www.gridwiseac.org/pdfs/workshop_091014/a_new_dist_sys_optr_construct_paper.pdf
[3] http://grouper.ieee.org/groups/scc21/2030.2/email/pdfDAY98JjKfF.pdf

Information and Communication Technology (ICT): Communications networks for connecting all parts of the grid which includes operators, service providers, customers etc.

Independent Market Monitor (IMM): Independent organization employed by ISO/RTO to monitor wholesale market activity

Independent System Operator (ISO): An independent, federally regulated entity established to coordinate regional transmission in a non-discriminatory manner and ensure the safety and reliability of the electric system[1].

Interconnections: A geographic area in which the operation of the Bulk Power System is synchronized.

Investor Owned Utilities (IOU): Utility which is privately-owned and whose stock is publicly traded.

Load Serving Entity: Secures energy and transmission services for serving the electrical demand and energy requirements needs of its end-use customers.

Municipally Owned Utility (Muni or MOU): Type of electric utility which is owned by a city or municipality.

North American Electric Reliability Corporation (NERC): A not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid[2].

Open Access Same Time Information Service (OASIS): An electronic posting system that the TSP maintains for transmission access data and provides simultaneous viewing access to all transmission customers.

Phasor Measurement Unit (PMU): A device that produces synchronized measurements of phasor (i.e. its amplitude and phase), frequency, ROCOF (Rate of Change Of Frequency) from voltage and/or current signals based on a common time source that typically is the one provided by the Global Positioning System UTC-GPS.[3]

Power Exchange: An entity providing a competitive spot market for electric power through day- and/or hour-ahead auction of generation and demand bids [FERC Glossary].

Power Marketer: Business entities who usually do not own generating or transmission assets but engage in buying and selling electricity.

Power Marketing Administration (PMA): Federal agencies within the Department of Energy, which carry the responsibility of marketing wholesale power from hydropower plants and the Columbia Nuclear Generating Station.

Regional Transmission Operator (RTO): See Independent System Operator (ISO)

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[1] https://www.ferc.gov/resources/glossary.asp
[2] https://www.nerc.com/AboutNERC/Pages/default.aspx
[3] IEEE Std.C37.118-2011

Regional Reliability Entity (RRE): Member of the NERC Council that is delegated authority to monitor and enforce compliance within its defined area.

Reliability Coordinator (RC): Entity responsible for the reliable operation of the BES, has the wide area view of the BES, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations [NERC Glossary].

Remote Terminal Unit (RTU): Perimeter SCADA devices interfacing with field sensors to measure and control actual physical devices

Retail Electric Provider (REP): Entity that sells electric energy to retail customers in this state but may not own or operate generation assets.

Retail Sales: Sales made directly to the end-use customers.

Supervisory Control and Data Acquisition (SCADA): A system of remote control and telemetry used to monitor and control the transmission system [NERC Glossary].

Static Synchronous Compensator (STATCOM): Shunt flexible AC transmission systems (FACTS) device for controlling power flow

Static VAr Compensator (SVC): Shunt-connected static VAr generators or absorbers for controlling the voltage at the point of coupling.

Tariff: A compilation of all effective rate schedules of a particular company or utility. Tariffs include General Terms and Conditions along with a copy of each form of service agreement [FERC GLossary].

Transmission Operator: An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems [NERC Glossary].

Transmission Service Provider: Entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable Transmission Service agreements [NERC Glossary].

Variable Energy Resources (VER): Production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator, for example, wind, solar generating facilities.[1]

Vertical Integration: The combination within a firm or business enterprise of one or more stages of production or distribution. In the electric industry, it refers to the historical arrangement whereby a utility owns its own generating plants, transmission system, and distribution lines to provide all aspects of electric service [EIA Glossary].

[1] Integration of Variable Energy Resources Notice of Proposed Rulemaking, FERC Stats. & Regs. 32,664, at P 64 (2010) (Proposed Rule).

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